COMPARATIVE ECONOMIC EVALUATION OF THE OPTIONS FOR TRANSPORTING THE ALASKAN NORTH SLOPE STRANDED GAS

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A

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ABSTRACT

The most effective economic parameter often considered in feasibility analysis is the Return On Investment (ROI). Any Alaskan gas pipeline project is expected to have a high return on investment to be considered economic.

A Comparative Economic (CE) model was used in this study to analyze the gas pipeline project options. These options are: The Alaskan Canadian (AlCan) Highway stand alone gas pipeline project, the AlCan Highway gas pipeline with an instate spurline to southern Alaska, the All-Alaskan Liquefied Natural Gas (LNG) Project , the All- Alaskan LNG project with a spurline to southern Alaska, and the Gas-To-Liquid (GTL) project. The CE model makes use of the Crystal Ball and some input parameters like cost, taxes, tariffs and price to determine the economic feasibility of each option based on the ROI, payout period and total revenue accrued from each project.

It was shown from the analysis that the AlCan Highway stand-alone pipeline project had the highest return on investment of 33%. This was followed by the AlCan Highway gas pipeline with an instate spurline to southern Alaska with return on investment of 32.6%. The all-Alaskan LNG projects proved feasible but with less return on investment compared to other options.

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CHAPTER 1

INTRODUCTION

The United States, like many other nations, has been on a quest for better and more efficient energy sources. Over the years, this quest has progressed through several different energy ages.

Oil, as a liquid fuel, was a lot more efficient than other energy sources, and the nation depended on it as a major source of energy. Recently, when it became quite clear that oil might soon be depleted, efforts commenced to find an alternative energy source.

Natural gas seems to be the answer. It is a clean, reliable and efficient burning fuel. It has a high octane number above 120 that actually makes natural gas the fuel and feedstock of first choice[1]. Unlike other liquid fuels, natural gas does not associate with unburned carbon during combustion, which reduces engine performance. The non-association with carbon deposits makes the equipment life longer and the performance better. Also the operational efficiency of natural gas fuel for industry also lies in its low carbon and sulphur emissions and greater efficiency in combined power plants.

In the United States, energy utilization has shifted from one energy resource to another. The present energy era is the natural gas era. In the 1970s, when the country reached its peak in oil production, there arose the need to substitute oil with another energy source. As predicted by Hubbert and Samiei[2], the energy crisis began as the rate of production declined. Hubbert and Samiei predicted how cumulative production can be affected by the rate of discovery. Fortunately Hubbert and Samiei were almost correct in their predictions as the country reached its peak production a year after they predicted it would. Hubbert and Samiei's conclusion followed a simple trend: increased rate of oil well discovery led to increased production, while reduced rate of oil well discovery led to reduced cumulative production.

Unfortunately, nobody gave a thought to their predictions until the crisis. Hubbert and Samiei[2] tried to prepare people for the forthcoming tragedy but little attention was paid to their predictions. The consequences were the severe energy crises the country suffered in the 1970's. This made true the common saying, "to fail to prepare is to prepare to fail".

It is evident that in the next ten years, the United States' demand for natural gas will be at its peak[3]. If the United States depends solely on other countries to supply all its energy needs, the price of natural gas will automatically increase due to its high demand, and will result in great economic loss to the country. It is expedient therefore that the country seeks the solution from within its borders. The abundance of natural gas in the Alaskan North Slope (ANS) affords the country a chance to avoid complete dependence on other countries and consequently save her from an economic crash. The earlier the United States realizes this and tackles it, the better. The country needs to efficiently utilize its own natural gas in the Alaskan North Slope reserve.

This leads to the recent challenge of transporting this natural gas from the ANS to commercially viable markets. It is a challenge since there are many policies and economic evaluations involved and different options, when it comes to the efficient transportation of this natural reserve. Some of these policies and economic evaluations will be analyzed in the later section of this study.

Currently there are many propositions on the best option for transporting the ANS stranded gas. This study presents an economic analysis of five basic routes which will aid in selecting the most favorable option in the transportation of ANS gas.

The five basic routes that are considered in this study are:

1. **The Alaskan Canadian (AlCan) Highway stand alone gas pipeline project**: This pipeline will follow the AlCan Highway and take the ANS gas through Alberta (Canada) to Chicago where the gas will be commercialized.
2. **The AlCan Highway gas pipeline with an instate spurline to southern Alaska**: This pipeline will follow the AlCan Highway route as described above but will incorporate a smaller pipeline to supply take off gas to the south. It can be taken to anywhere in the south, maybe Anchorage to supply the increasing energy demand for industrial purposes
3. **The All-Alaskan Liquefied Natural Gas Project**: This project will transport ANS gas to Valdez where it will be liquefied and transported in vessels to the Pacific market including China, Japan and Korea.
4. **The All-Alaskan Liquefied Natural Gas project with a spurline to southern Alaska**: This project is similar to the all-Alaskan LNG project but it will also include an instate pipeline to supply gas to the state. This will involve a smaller pipeline to supply gas before the major pipeline terminal in Valdez.

5. **The Gas-To-Liquid (GTL) project**: This is a proposed potential plan to convert the natural gas to liquid distillates and blend it with the ANS oil being produced and then transport the blend through the existing oil pipeline, the Trans-Alaskan Pipeline System (TAPS).

1.1 Objectives and Scope of Study

The fundamental objective of this study is to identify, evaluate and compare the possible options of transporting the "stranded" Alaskan North Slope gas to the market. The scope of the objective will include:

1. To evaluate energy demand and utilization in the United States, and hence the need for Alaskan North Slope gas.

2. To appraise past recommendations on the different options for transporting the Alaska North Slope gas to market.

3 To determine the existing gas demand and supply in the two major markets (the North American Market and the Pacific Rim Market) for ANS gas and make a consequential analysis of their effect on the choice of the gas project.

4 To make a 30-year future/forward projection of the different projects using the Northern Economic Research Associates (NERA) pipeline model [4].

5 To identify and compare gas transportation options based on various economic parameters that include Return-On Investment (ROI), payout period, project Profit and Total Cost of the project.

CHAPTER 2

LITERATURE REVIEW

The task of transporting the ANS gas has been a great concern for the state of Alaska and, indeed, the entire nation. Several investigators and researchers [3,4,5] have presented numerous analyses and tried to come up with the most economical way of transporting this gas. Interestingly, they have all come to different conclusions and presented varying options. Researchers [4,5,6] have gathered a lot of information on this subject and have also arrived at different conclusions; as expected, they have proposed different options. The Alaskan Natural Gas Development Authority (ANGDA), while proposing the All-Alaskan LNG Project option, has concluded that the all-Alaskan project has the potential to bring up to **$500** million per year in new revenue to the state, **16,000** jobs during construction and **lower energy bills** to residents throughout Alaska[5]. The Northern Economic Research Associates[4] and Reynolds[6], while determining the economic feasibility of the various pipeline options, concluded that the AlCan Highway route is more feasible due to the gas market.

Virtually all the proposed options [4, 5, 6] have proved to be feasible individually. The major problem is choosing the best option to economically transport ANS stranded gas to market. Despite their authenticity and advantages, some of the options, for instance Over-The-Top (OTT) and the Y- line, have many disadvantages to both the state government and investors. OTT route, which will supposedly pass through the Beaufort Sea and therefore constitute some negative environmental impact to the state, has a big disadvantage. The pipeline has been evaluated to be the shortest route with estimated distance and initial delivery of 2900 miles and 3.3 Bcfd[7], respectively. This route has also been known as the cheapest option, with an overall cost estimate of US$3.35-3.6 per mmbtu[7]. The OTT route is shown in Figure 2.1[7].

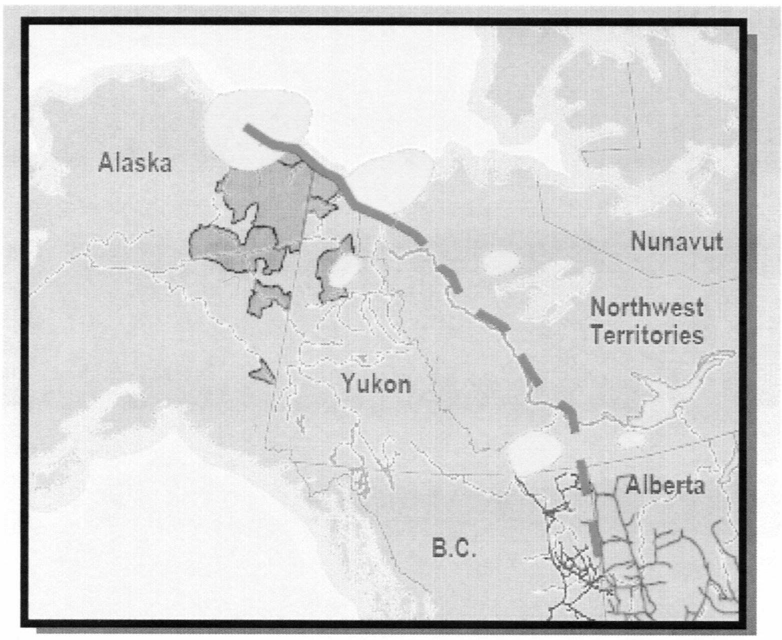


Figure 2.1[7]: Over the Top Route

The first question to be answered is: *why transport this natural resource?*

Another proposed option, although not modeled in this work, is the Y-Line route. This route combines the AlCan Highway route and the all-Alaskan LNG project. The pipeline will go from North Slope to Delta junction where it will split into two: one line going to Valdez and the other to Alberta.

At Valdez, the gas is liquefied and follows the LNG project route while the pipeline leading to Alberta follows the AlCan Highway route. The Y-Line route tends to exhibit combined benefits of the AlCan Highway and all Alaskan LNG project. Likewise it combines the disadvantages of both. Its major challenge is the marketing of the LNG in a very highly competitive market.

Comparatively, the Y-Line route is likely to be capital intensive and complex. This will consequently affect the cost of gas to be sold as LNG in the Pacific Rim. Increased cost of Alaskan LNG project will no doubt leave the gas unsold since there are other producers like Indonesia, Australia and Russia who are willing to sell their gas for less and still make a profit.

2.1 Energy Demand, Supply and Utilization in the United States

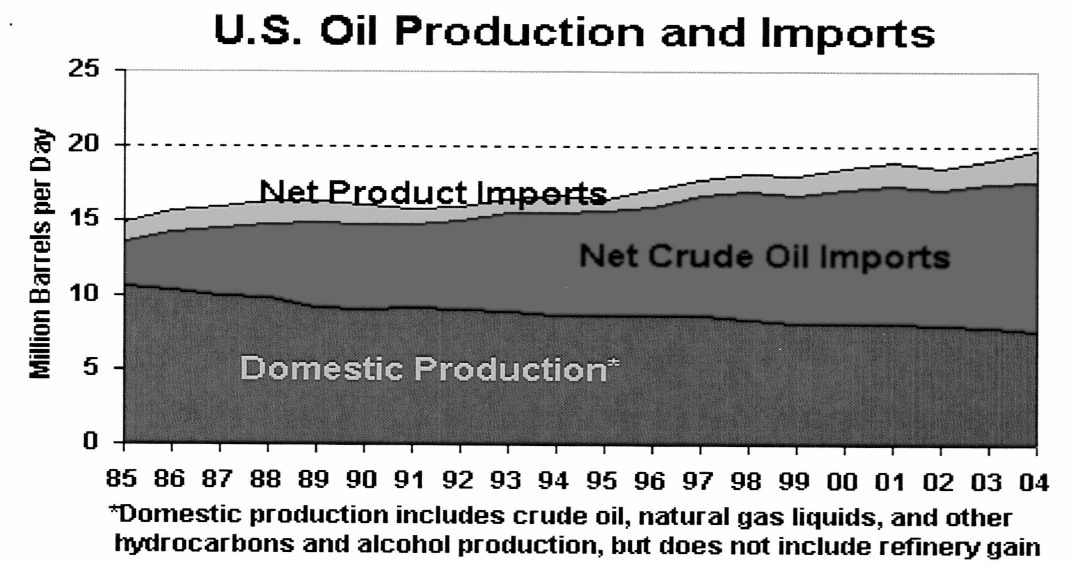
The United States has an opportunity to commercialize and utilize the Alaskan North Slope gas and avert energy starvation when the fast- depleting oil resource is completely exhausted. U.S.A. proven oil reserves have declined some 17% since 1990, with the largest single-year decline (1.6 billion barrels) occurring in 1991. Also, U.S. total oil production in 2003 declined sharply (around 2.8 million bbl/d, or 26%) from the 10.6 million bbl/d averaged in 1985[8] .

The demand for energy in the US has been on the increase despite the decline in oil production. In the past three decades, US energy consumption increased by 42%. In 2003, the United States was estimated to have consumed 98.1 quadrillion Btu (25% of the world's total energy consumption)[3]. This has led to increased dependence on importation. The United States' averaged total net oil (crude and products) imports were an estimated 11.8 million bbl/d during January-October 2004, representing around 58% of the total U.S. oil demand[1]. For a country the size of the US, these reports do not look very promising. The US oil production and oil imports between 1985 and 2004 are shown in Figure 2.2[3].

Following this trend of heavy dependence on crude oil imports, it is obvious that the world needs to identify alternative sources of energy and make them affordable and reliable.

With an abundant Alaskan gas reserve of approximately 39 TCF of proven reserves in Prudhoe Bay and an expected 65 TCF more along the Beaufort and Chukchi

Sea shores, Alaska North Slope gas is no doubt a significant and economic energy alternative[6]. Gas pipeline economics and forecasts have been on the increase and consequently Alaska gas pipeline options are becoming more crucial and the subject of economic evaluations.



Source: http://www.eia.doe.gov/emeu/cabs/Usa/Oil.html

Figure 2.2[3]: U.S. Oil Production and Imports between 1985 and 2004

2.2 The Alaskan Canadian (AlCan) Highway Stand-alone Gas Pipeline Project

The Alaskan Canadian highway route will take the ANS gas through the Alaska interior and to Alberta and finally to markets in the lower 48 as shown in Figure 2.3. This pipeline can transport 2-6 BCF per day depending on how much gas is available.

The AlCan Highway route will possibly include the refining and use of Natural Gas Liquids (NGL) for a petrochemical industry already situated in Alberta. These NGLs can also be very useful in Alaska if a new petrochemical industry is built anywhere in its interior. The petrochemicals produced from a petrochemical plant, if built in Alaska, can easily be transported through the Alaskan Railroad from North Pole to Anchorage for shipment to the Pacific Rim. An excellent advantage to the AlCan Highway route is the possibility of including a petrochemical plant. This gives Alaska the chance of utilizing some of the North Slope gas to develop industry in interior Alaska. The extraction and sale of NGL enhance the feasibility of the AlCan Highway route.

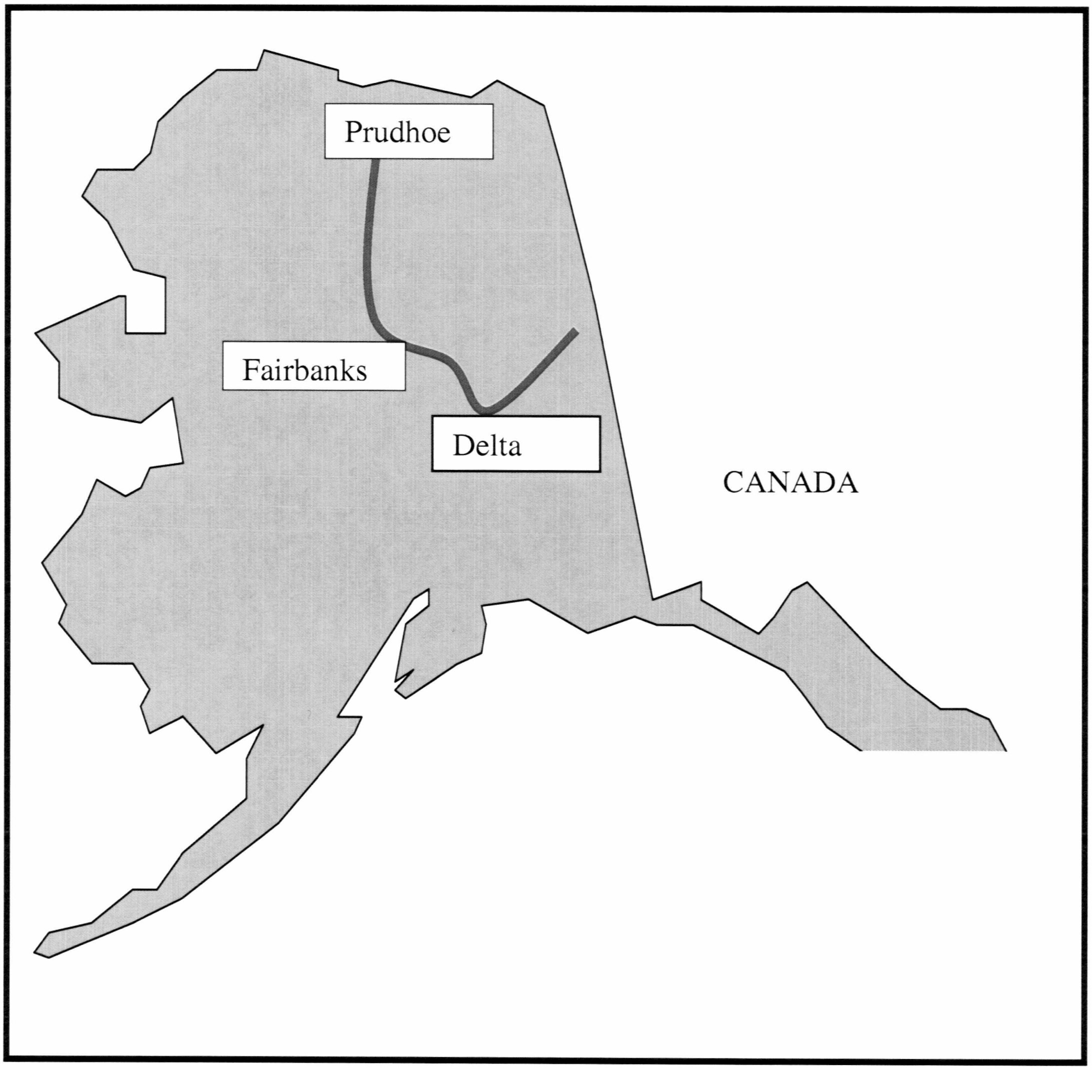


Figure 2.3: Proposed AlCan Highway Stand-alone Gas Pipeline Route.

2.3 The AlCan Highway Gas Pipeline with an Instate Spurline to Southern Alaska

This option will follow the same route as the AlCan Highway stand-alone but it will include a spurline at Glennallen to transport gas off from the mainline to southern Alaska.

2.4 The All-Alaskan Liquefied Natural Gas Project

The all-Alaskan LNG project will be designed to bring the Alaskan North Slope gas to the Alaskan southern shore where it will be converted to LNG. The project therefore has two major stages.

The first stage is a pipeline from Prudhoe Bay to Valdez. This pipeline conveys the ANS crude to Valdez where it will be converted to LNG. The second stage is the liquefaction. In the liquefaction stage, natural gas is super-cooled to -256 degrees Fahrenheit. This process liquefies the natural gas by compressing it to almost $1/600^{th}$ of the original volume. This is actually a great reduction in the volume and makes it easier for the liquefied gas to be stored in vessels and transported through the sea. The LNG will then be sold on the Pacific Rim market, which mainly consists of Japan, China, Korea and Taiwan.

The major challenge in the project is the market for the LNG. The ability of the all-Alaskan LNG project to compete with already existing LNG producers and marketers in the Pacific Rim is uncertain. The competitors – Indonesia, Australia and

Russia - have cheaper gas to sell than Alaska. A reduction in the Alaskan LNG market price will inevitably leave the project futile.

2.5 The All-Alaskan Liquefied Natural Gas Project with a Spurline to Southern Alaska

This gas pipeline option will also follow the same mainline route as the All Alaskan LNG stand alone project but with a spurline at Glennallen to Anchorage. This is shown in Figure 2.4

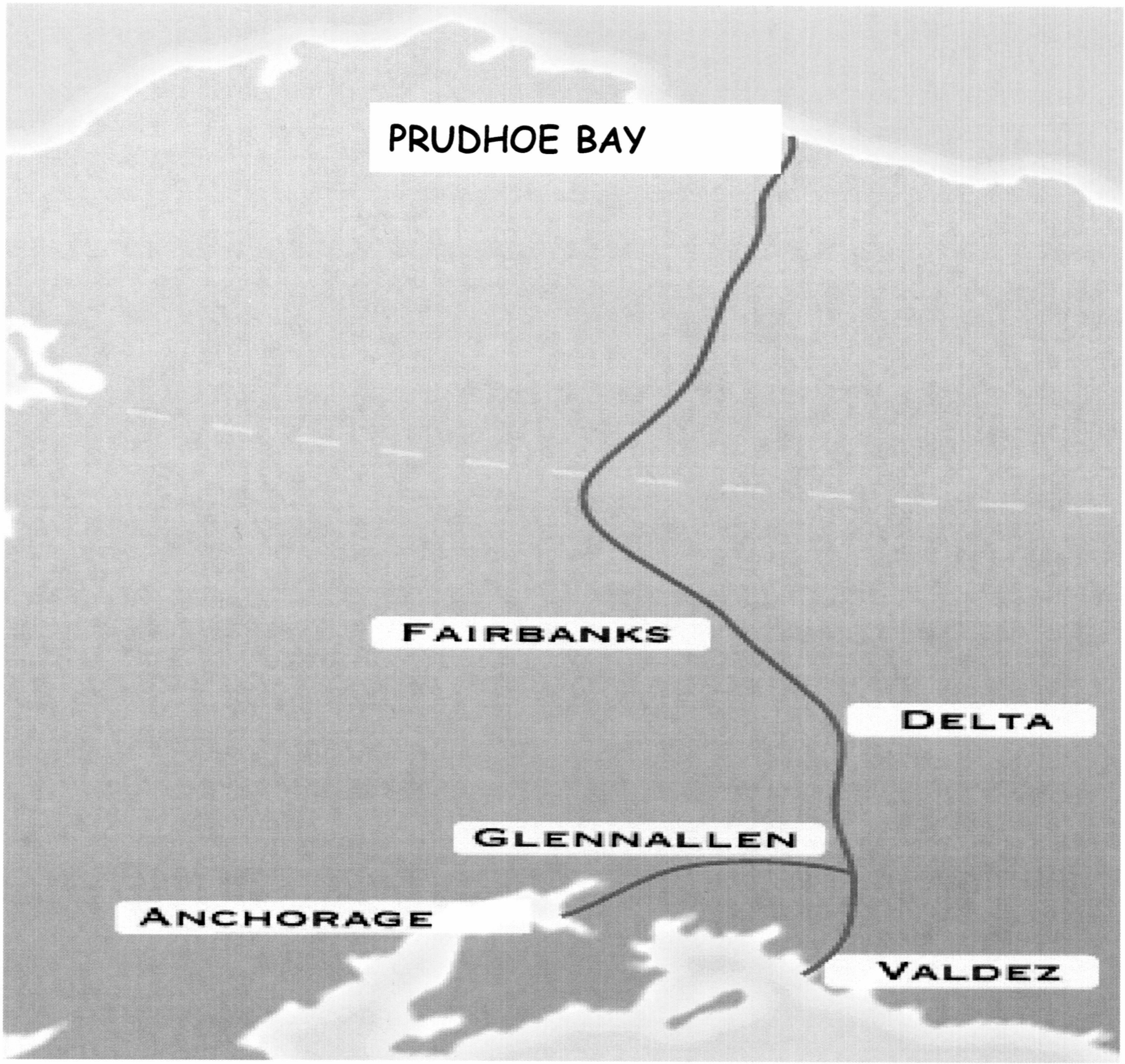


Figure 2.4: The LNG Pipeline Route with a Spurline to Southern Alaska

2.6 The Gas-To-Liquid (GTL) Project

The GTL option does not entail building a new gas pipeline, but makes use of the existing Trans Alaskan Pipeline System (TAPS). The utilization of a pre-existing pipeline makes this option a very attractive one. The proposal is that the gas be converted to liquid distillates and then transported through the existing oil pipeline (TAPS).

Several scholars[9, 10] at the University of Alaska Fairbanks have conducted feasibility studies on GTL products and transportation through TAPS. In 2003, Ejiofor[9] in his work recommended a batching approach for transporting the Gas-To Liquid products from the North Slope of Alaska to Valdez due to its higher return on investment when compared to the commingling approach. Ibironke [10], while evaluating the economics of Gas-To-Liquid, crude oil commingled product transportation through TAPS concluded that the Commingled Mode of transportation is more economic and less risky because it showed lower Net Present Value (NPV) than the batch mode of transportation.

2.6.1 Synthesis of GTL

The Gas-To-Liquid (GTL) option uses the Fischer-Tropsch process where natural gas (methane) is chemically and catalytically converted to liquid distillates. At first, the methane (CH_4) is converted to synthesis gas ($CO + 2H_2$). The synthesis gas is passed through a conversion unit that uses the Fischer-Tropsch process to chemically and catalytically convert the synthetic gas to synthetic crude. This synthetic crude is finally passed through a hydrocracking unit for the production of liquid distillates such as diesel, kerosene, ethanol, dimethylether (DME), naphtha and waxes as shown in Figure 2.5[11]

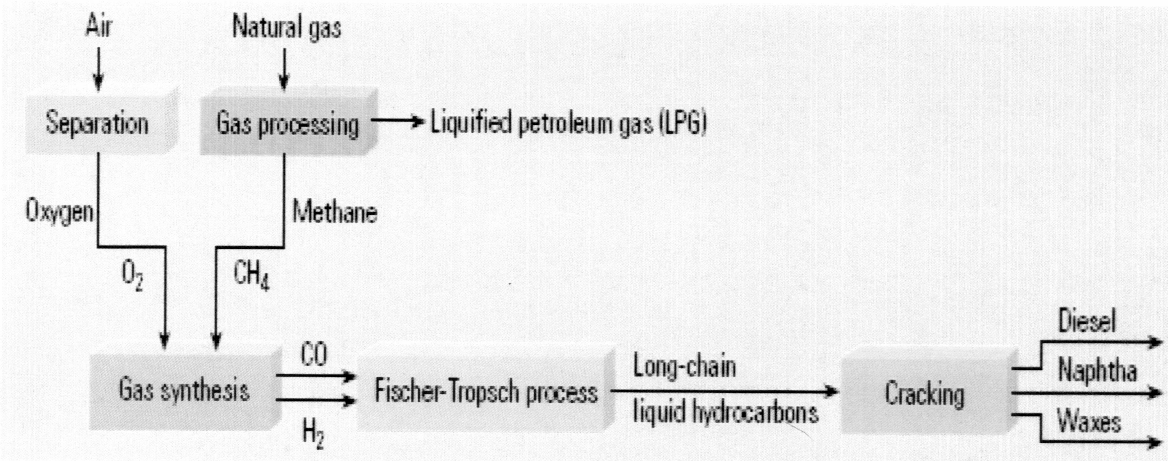


Figure 2.5: GTL Process[11]

The GTL products can be transported through the existing TAPS either by batching or commingled with crude oil.

CHAPTER 3

ANALYSIS OF SOME TECHNICAL AND GOVERNMENT POLICIES

The task of building a pipeline has a lot of challenging issues behind the actualization. It is therefore pertinent to analyze these issues which include technical, government (policy) and environmental issues.

3.1 TECHNICAL ISSUES

The task of transporting the ANS gas to a viable market is not only dependent on the market but also on some technical issues. Due to the geographical area in consideration (the arctic region), it is expedient to use the most suitable technology when considering pipeline design and construction. Arctic pipelines present significant challenges and opportunities.

Some design parameters include:

1. Pressure.
2. Temperature.
3. Flow rates.
4. Pipe sizes and wall thickness as per regional conditions.
5. Routing details and stop valve locations.
6. Stress and strength calculations.
7. Corrosion protection systems.

The design will also account for maximum allowable differential ground movements due to frost heave. This will include the capacity of a piping system to tolerate differential movement providing monitoring and maintenance criteria.

Construction is the major capital cost component. The construction will take into account the procedure and quality control testing. Pressure testing in the arctic has resulted to a lot of challenges due to limited water supply, and the environmental concern for disposal of water.

The design process itself includes the development of cost estimates for various possible combinations of pipe size, compression equipment, and inter-station distances to find the combination that minimizes transportation cost given the desired flexibility and expandability goals.

3.1.1 Excerpts from Code of Federal Regulations Design Factors to be Utilized for Natural Gas Pipeline

In the design of steel natural gas pipelines the Minimum Yield Strength for the grade of steel used is reduced by a Design Factor (F). This Design Factor is determined by the type of road being crossed by the pipeline and a Class Location established by Code of Federal Regulations, Title 49, Part 192[12].

The Class Location depends on the occupancy of buildings or activities within an area that extends 660 feet (200m) on either side of the pipeline centerline for a continuous 1 mile (1.6 km) segment of the pipeline.

The four Class Locations are as follows[12]:

Class 1: A location that has 10 or less buildings intended for human occupancy.

Class 2: A location that has more than 10 but less than 46 buildings intended for human occupancy.

Class 3: a) Any location that has 46 or more buildings intended for human occupancy; or

b) Area where pipeline lies less than 300 feet (91 m) of either a building or a small well defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons at least 5 days a week for 10 weeks in any 12-month period. (The days or weeks need not to be consecutive.)

Class 4: Location where buildings of four or more stories are prevalent.

Due to the high cost of materials and construction procedures in the Arctic, choosing a suitable design and construction is essential. This will also affect the route to be chosen to transport the Alaskan North Slope gas. The route that will show the least problematic conditions will be a route of better choice. This is due to the fact that this will be comparatively less expensive and easier to manage and maintain.

Some of the challenging factors that are likely to be encountered in the arctic region will include but are not limited to:

1. **Permafrost**

Permafrost is soil that has remained frozen for two or more years. Frozen means colder than 0^0C or 32^0F. Permafrost is a major factor in the geography of Alaska. It exists where summer heating fails to penetrate to the base of the layer of frozen ground. Permafrost covers most of the northern third of the State.

2. **Muskeg**

Muskeg is the expanse of spongy, poorly drained, peat like organic matter overlaying a permanently frozen bog. Like a soggy blanket draped over the landscape, muskeg, or peat bog, covers more than 10 percent of southeast Alaska. The water level in muskeg is usually at or near the surface. Stepping on muskeg is like stepping on a sponge, and walking across it involves avoiding the multitude of open ponds that range in size from potholes to small lakes. Despite their innocuous appearance, muskeg holes can be more than just messy - they can be dangerous. Some are quite deep and offer no toeholds to help the unwary climb back out. Similar to permafrost, muskeg raises a lot of challenges to pipeline route construction.

Muskeg poses a significant problem during construction. It can be very dangerous and arduous. During the 1870's muskeg in Northern Ontario was reported to have swallowed a railroad engine whole when a track was laid on muskeg instead of clearing down to bedrock[13]. Many other instances have been reported of heavy construction equipment vanishing into muskeg in the spring as the frozen muskeg it was parked on during winter thawed[13].

Ambient temperatures have a direct influence on the fluid characteristics, operating pressures and pipeline flows, including the handling of Natural Gas Liquids (NGL) for gas pipelines. Extreme arctic conditions drastically affect the ambient pipe/fluid temperature interaction, including the pipe temperature gradient. For example, above-ground pipelines cool rapidly due to convection and low ambient temperatures. The impact on the below-ground arctic pipelines is larger due to the presence of permafrost and the likely degradation of the permafrost. Permafrost degradation can occur when the temperature in the pipe is higher than the ground temperature. The main consequence of permafrost degradation is failure of the soil/pipeline interaction of pipe foundation, which leads to thaw settlement. The opposite phenomenon, frost heave, occurs when the pipe temperature is lower than the surrounding soil, which then causes the unfrozen soil to freeze [13].

To stabilize the pipe, there are a number of different possible solutions. These will include gas chillers and different pipe/soil foundation enhancements. Arctic pipeline risks and uncertainties have a large impact on the cost and safety of constructing a gas pipeline.

3.2 Government Policy

Government policies affect the possibility of building a pipeline. Some policies are favorable while some are not. Rigid and unfavorable policies can increase the cost of constructing a pipeline.

To encourage investors both the federal and state governments should provide tax incentives to any agency that wishes to invest in the pipeline. This reduces the cost of the pipeline project, improves the feasibility of the project and thus gives a clearer basis for comparison of the different routes.

The all-Alaskan LNG project seems to benefit from this, since it will be owned by the state and it already has federal tax waiver. The federal tax waiver reduces the overall cost of building the all-Alaskan LNG project and thus leaves the project comparatively less expensive.

The most important policy the state can pursue in order to encourage investors to build a gas pipeline is the creation of tax incentives. There are so many incentives applicable and therefore it is hard to conclude which incentive is most beneficial.

Some of the tax policies will include:

3.2.1 Property Tax and Back-end Loading:

Property taxes are those taxes levied by the government against either real or personal property. The right to tax real property in the United States rests exclusively with the states, not with the federal government. Sometimes in exchange for paying no fees upfront, the investor pays an annual fee for marketing and managing that is higher than the fees charged for a front-load fund. This is called the back-end load. This occurs when government revenues are lower in the beginning of the project but increase later. This is a property tax policy that can be used to induce new investment. The overall effect is that the government will receive the same amount or even higher revenues during the course of the project, but the producers will get a higher Return On Investment (ROI). Back-end loading will be helpful to investors since it can have a leveraging effect on the Return on Investment. Because of the time value of money and interest payments, cost incurred at the outset of a project have a much greater effect on the ROI than the costs later. One of the most important tax reductions for the purpose of back-end loading is a property tax holiday or deferment during construction. Paying property taxes during construction is quite difficult because there are no revenues to offset these expenses and the firm might have to borrow some money to pay the tax.

Back-end loading is a good idea but should be used as a bargaining chip by the state for other concessions such as future access to natural gas from the pipeline. In other words, we should not consider one specific tax change in isolation, but should work towards a broad range of tax changes and policies that will be both satisfactory to the investors and beneficial to the state in terms of economic development and environmental concerns.

3.2.2 Progressive Taxes:

Progressive taxes are taxes that take a larger percentage from the income of high-income people than it does from low-income people. Most taxes are considered to be progressive. In a gas pipeline project, the progressive tax will entail that the rate of taxation at the well head is low when gas prices are low and high when the gas well head prices are high. The overall effect is to reduce the volatility of investors' revenues at times when gas prices are going up and down. This will encourage producers to build gas pipelines and even to explore for and develop new gas reserves.

3.2.3 Tax Free Bonds:

Another way the Alaska state policy can encourage investment in the building of a gas pipeline to transport ANS gas is to sell tax-free bonds through the Alaskan Railroad Corporation. This will in turn create more business for the railroad. The use of tax-free bonds can increase the ROI for a project, making it more feasible. The exact increase in feasibility depends on the debt equity ratio used and on the method of comparison between an equity-financed project and a debt-financed project. Another factor is also the ability to use interest rates for deductions. Interest is tax deductible. That will lower the interest rate required to sell bonds.

3.2.4 Reserves Tax

This is policy that induces gas development. This means taxing the underdeveloped ANS gas reserves. This could be considered as a penalty for leaving the gas reserve undeveloped. This is a kind of disincentive that can be used to induce oil and gas companies to develop ANS gas reserves. If a project for development of ANS gas shows a low ROI, then the gas producers will obviously lose money. They can legally claim that reserves tax is unreasonable since the gas has a higher value as an undeveloped resource.

3.2.5 Impact Funding

Impact funding can be a tool to pay for economic impacts on communities during pipeline construction. One aspect of any large-scale project is the impact it will have on local communities. Although the large-scale project will create jobs; there may be costs imposed on individual communities.

If the state can give impact funding, it could create more support for early tax breaks such as an early property tax break among the local governments. During the construction of a gas pipeline, there might be impacts on the various communities in Alaska. These impacts may include crowded schools, the need for extra police, firefighters, medical caregivers, etc. To pay for some of these immediate and possibly high costs, the state can consider providing impact funding to the affected communities.

3.2.6 **Royalty-In-Kind:**

Royalty-In-Kind (RIK) is when the producers pay royalty to the state by giving a product worth 12.5% of the well-head value of gas. RIK works by allowing the state to take its royalty from the producers as a commodity and in this case, natural gas, instead of taking it as a cash payment.

RIK reduces the administrative burden for government and industry because it relies less on auditing and application of complex valuation methodologies. It is an essential tool for the state of Alaska to induce competition for gas development in the North Slope. It can create a more competitive gas labor market on the ANS and higher lease sale revenues for the state and more intensive gas exploration and development. Essentially, it will expand the gas industry.

3.2.7 **Federal Tax Break Legislation**:

The natural gas pipeline may or may not be feasible without any federal tax break legislation. With a federal tax break, the United States as a country has a chance to share in the risk involved in the pipeline project in order to better secure energy supplies. In other words, some of the risk of a pipeline becoming unprofitable is taken over by the federal government in return for a reduction in the risk of a future energy crisis.

The Comparative Economic (CE) model was used irrespective of these policies, except for the All-Alaskan LNG project, which has a federal tax waiver. Any change in the policies will affect the economics and results of the CE model.

3.3 Environmental Issues

Natural gas is clearly the fuel of choice in the United States, as it is relatively clean burning, efficient, and more economical than in years past due to improvements in supply-chain technology. The effects of the environmental impacts are assumed to be so minimal that they will not affect the results of the economic analysis of the different gas pipeline projects.

3.4 Evaluation of the Effect of the Market Potentials

The competitors in the particular market, the demand of gas in that market and the proximity of the market to the gas well, are all factors associated with the market. The fundamental gas market drivers include:

1. Weather.
2. Deliverability/transportation fluidity.
3. Storage capacity.
4. Supply reliability.
5.

3.4.1 Weather

Weather is a key component in affecting natural gas supply and demand. In its simplest form, the colder the winter, the higher the gas consumption rate to heat homes, satisfy industrial processes and fulfill commercial uses. Similarly, in the summer, the hotter the weather, the higher the air conditioning needs, thus calling up gas-fired power plants to handle the additional peak loads. Consequently, upward price pressure can now be seen in both seasons. This is unfortunate, but weather is a systematic (non-diversifiable) risk of energy commodities, an effect that can be partially mitigated by optimal storage management, continued economical supply procurement and recently developed weather derivative products.

3.4.2 Transportation

The Energy Information Administration (EIA) estimates that there are over 285,000 miles of interstate gas pipelines within and coming into the United States and almost one million miles of intrastate local utility pipelines [14]. Together, these pipelines are delivering approximately 60-70 bcf/day of supply. Although these types of figures appear comforting, indicating redundant capacity to deliver gas from producing regions to consuming regions, frequent weather-driven demand changes and consumption growth pressures can lead to congestion at several key delivery points at both ends of the chain. No area of the country is immune to this event, as we have seen weather and demand driven prices spike to exorbitant rates for both gas and power on the West Coast and East Coast and in the Midwest.

3.4.3 Storage

Storage, mainly in the form of underground basins, wells, aquifers, salt caverns, above-ground tanks and subterranean reservoirs, can provide price buffers and supply "protection" to end users in the sense that risks associated with exact timing of delivery from producing regions to ultimate consumption (a form of "just-in-time inventory" risk) can be ostensibly mitigated.

Currently, there is an estimated 7,000 bcf of total proven base and working gas storage capacity in the United States [14]. Growth in this capacity is expected to continue as supply-and demand-related price pressures exist. Figures on net storage injection (summer months) and withdrawal (winter months) are published weekly by the EIA and are eagerly anticipated by market participants[14]. The domestic gas markets behave commensurately with expectations of these injection or withdrawal figures, with prices generally rising with higher than expected withdrawals or lower than expected injections, and prices generally falling with lower than expected withdrawals or higher than expected injections, per consumption.

The analytical expression of this relationship is further clarified when performing a regression analysis between heating degree days (HDD's) and cooling degree days (CDD's) versus storage levels. One can see that an increase in HDD's in the winter months creates more storage withdrawals (therefore creating less net storage volume), thus creating price support levels (net upward price pressure). The converse is true in the summer months, when an increase in CDD's leads to a greater storage injection (therefore creating more net storage volume), and creating price ceilings (net downward price pressure).

Relative to the large amounts of natural gas produced, transported and ultimately consumed in the United States market, storage capacity is small. The disparity in current storage capacity as compared to total consumption will only be exacerbated with increased gas demand projections. Therefore, short- or long-term changes in market fundamentals (or combinations of both), such as weather patterns or gas load growth, can still have a significant effect on prices going forward.

3.4.4 Supply and Demand

Long-term downstream demand for gas is usually created from an expected increase in population, regional commercial business growth, industry growth, and power generation. Thus, the major sources of this consumption can be broken down into four primary classes: residential, commercial, industrial and power utilities. The North American natural gas demand and supply are shown in Figure 3.1 and Figure 3.2.

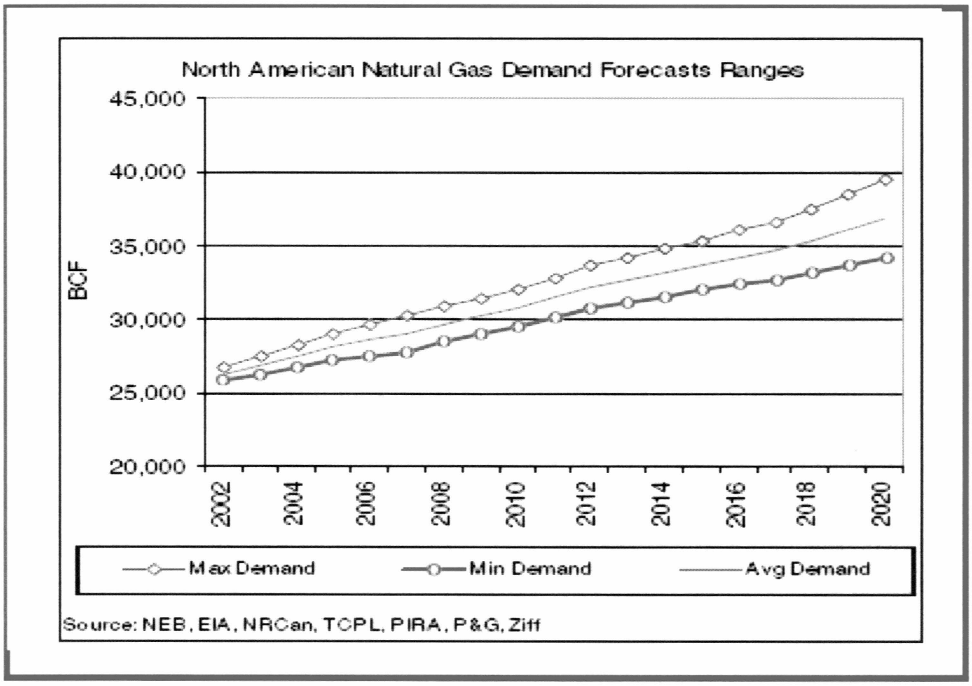


Figure 3.1: North American Gas Demand Forecast[15]

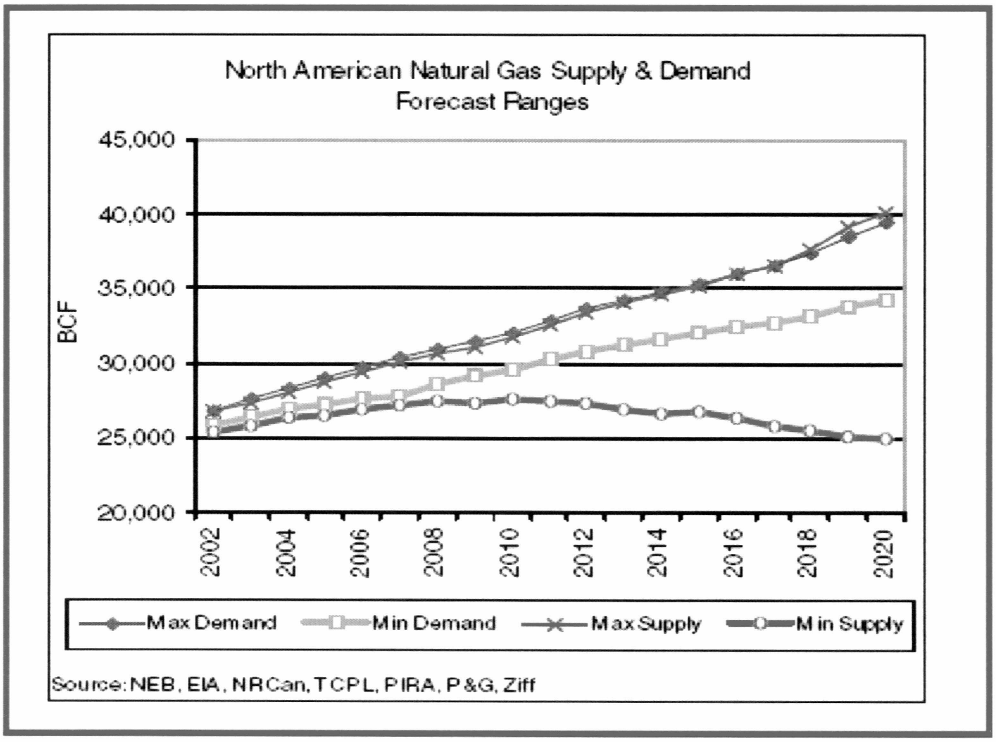


Figure 3.2: North American Natural Gas Supply and Demand Forecast[15]

Market participants need to be fully informed and abreast of the demand and supply in each region, knowing who is participating in bringing this gas to market, and what the economic valuation and cost of these projects are compared to the prices in the market that will sustain them. Combinations of this new gas supply, technology improvements, storage management, transportation optimization, demand-side management and weather risk management all play a major role in future gas market stability. Presently, the two huge markets are the North American market and the Pacific Rim market.

3.4.4.1 The North American Market

The demand for gas in North America is increasing at about 2% per year[6]. Increases in demand are expected to be 1.8TCF by 2005, 4.5TCF by 2010 and 10.5 TCF by 2020. The market opportunity for Alaskan gas in North America will be substantial in the near future. Natural gas prices increased steadily during 2000, as demand for gas-fired electric power production grew sharply. When cold winter weather arrived, heating demand – coupled with ongoing electric power demand – drove spot prices up. In one short-lived and isolated episode, gas touched $30 per thousand cubic feet (MCF) – the energy equivalent of $175 per barrel oil. Residential customers rarely buy spot market gas themselves. At the start of 2001, they were paying just over $9 per MCF for delivered gas on a nationwide average basis, an increase of 39% from a year ago. Most gas supply arrangements only offer short-term protection against price volatility; they ultimately converge on spot prices.

Large commercial, industrial and electric generation consumers generally procure their own gas supplies and arrange for transport. Since they do not have to pay local utility distribution charges, these big users pay less for delivered gas. For 2000, industrial and utility users paid about 40% of residential levels. Low wellhead prices and deregulated long-distance transport costs led to growing demand during the 1990's. Demand – which grew 36% from its 1986 low – reached a peak in 1996 and 1997. Most notable was demand from gas-fired electric power plants, where consumption rose by almost 50% during the 1990's.

Warmer winters in 1998-99 and 1999-2000 kept gas demand low, and masked a decline in supply. As U.S. gas output fell about 9%, prices remained stable until 2000. Another mitigating factor has been growing imports from Canada, which helped offset most of the domestic output drop. Imports held prices steady into 2000, when the growth in demand interacted with inelastic supply and prices rose sharply. Late-January spot prices now are in the $7 to $8 range, plus transportation and distribution charges. If average flowing gas prices converge on spot, current markets suggest that residential prices, for example, could rise by another $1 to $2 per MCF.

3.4.4.2 The Pacific Rim Market

The Pacific Rim market includes Japan, China, Korea, Taiwan and California. The Asia-Pacific market is the largest market, accounting for more than 70 percent of the world's trade. Until now, the Asia-Pacific market has been dominated by North Asian buyers with Japan importing 50 percent of global production.

Uncertainties remain about how gas demand in individual Asian markets will evolve. Robust growth, driven by the need for clean energy, is expected across the region. Nonetheless, it may be difficult for the supply projects around the Pacific Rim to sign up buyers as quickly as they would like[6].

The demand potential for the next decade from this area is about 20 million tons per annum (MTA) of LNG, but gas from Australia and the Middle East can put about 60 MTA of additional output on the market[6]. The comparative economic (CE) model assumed that the Alaskan LNG will be sold at the Pacific Rim market. Alaska will have to lower the price of its LNG to find enough demand to sell its product. Comparatively, the Alaskan gas will be uncompetitive.

CHAPTER 4

ECONOMIC PARAMETERS AND METHODOLOGY

The economic parameters are analytical variables that show how economically feasible a project is. These parameters will help determine which gas project transportation option is the most viable option. The basic parameters and assumptions made to generate the economic model used to comparatively analyze the pipeline projects are discussed below.

4.1 Return On Investment

Return On Investment (ROI) on a project is when all the cash flows encountered in the project are discounted into a zero net present value using one interest rate. It is an important measure of the feasibility of a project[6]. The higher the ROI, the more profitable the project. One of the biggest issues facing a natural gas pipeline project is profitability[6]. Hence, ROI is used to determine the profitability of any project.

The Return On Investment (ROI) can sometimes be calculated using the Du Pont ROI formula, which appears in the graphic illustration below[16].

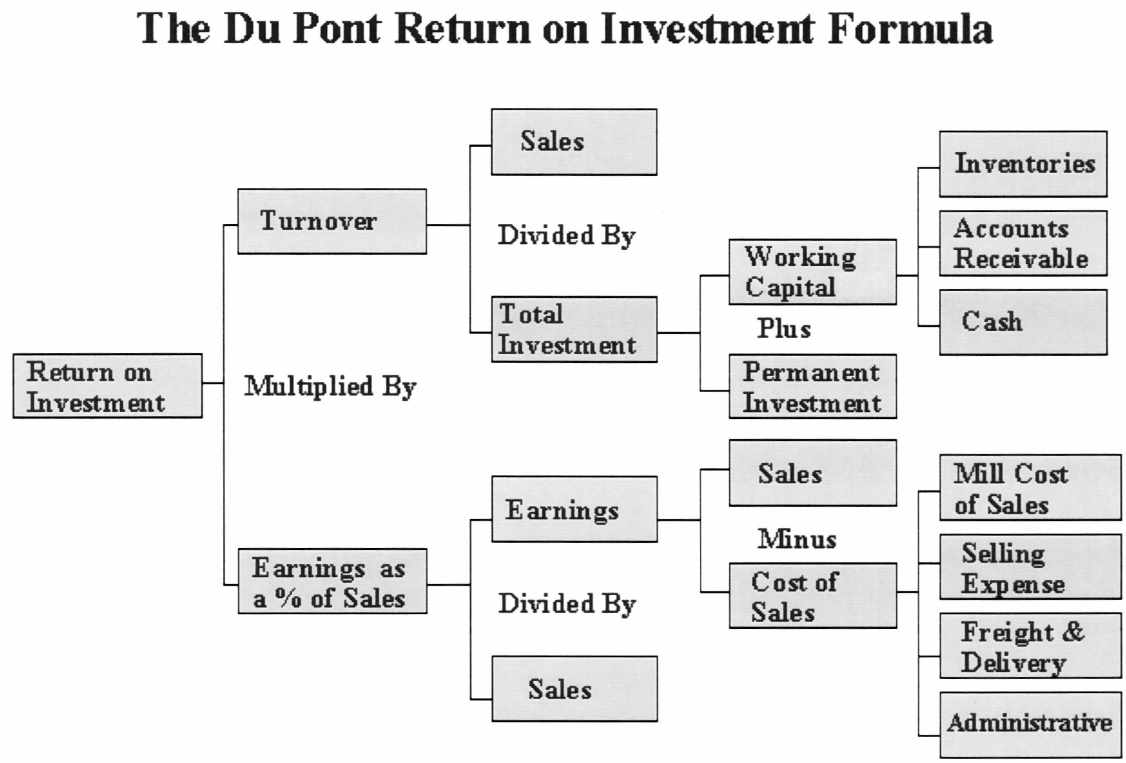


Figure 4.1: **The Du Pont ROI Formula**[16]

4.2 Hurdle Rate

The average ROI for alternative investment is called hurdle rate. Hurdle rate is the lowest ROI that an investor or company is willing to accept for investing in any given project[5]. If an investment has an expected ROI higher than the hurdle rate, then it is usually a good and feasible investment. If an investment has an expected ROI lower than the hurdle rate, then it is generally non-feasible and should not be considered. This is to say that the hurdle rate determines feasibility.

The Northern Economic Research Associate (NERA)[4] analysis suggests that the appropriate hurdle rate for the Alaskan gas project is in the range of 11%- 15%.

4.3 Weighted Average Cost of Capital (WACC)

The Weighted Average Cost of Capital measure has been shown to be an accurate approximation of a firm's internal hurdle rate for financing decisions[6]. It estimates the acceptable return on investment of any project. Therefore, the WACC concept is a good approximation of what kind of hurdle rate is required for projects.

It is computed using the following equation[6]:

$$WACC = \frac{Equity}{Equity + Debt}(MarketRate)*(Risk\,\Pr emium) + \frac{Debt}{Equity + Debt}*(DebtRate*(1 - TaxRate)) \qquad (4.1)$$

4.4 Capital Cost and Operation and Maintenance Cost

The Capital cost in this model includes:

- Conditioning plants to remove the carbon dioxide and other impurities from the gas before it is transported through the pipe line.
- Pipeline cost
- Liquefied Natural Gas (LNG) plants- to liquefy the natural gas.
- Tankers- to keep the natural gas in the liquefied state
- Natural Gas Liquid (NGL) plants- to extract propane, ethane and other heavier hydrocarbons from the natural gas leaving it purely methane gas.

The cost for each of these projects varies depending on the locations. Pipeline cost in Canada is lower than in Alaska and the cost varies by terrain. The Comparative Economic (CE) model therefore uses a measure of dollars-per inch –mile as the general cost estimate for the pipeline. This makes the model flexible for different size projects. Table 4.1 shows the breakdown of the capital costs used in this model.

Table 4.1: Breakdown of Capital Costs of the Different Projects.

project	Conditioning plant ($mill)	Pipeline($mill)	LNG plants($mill)	Tankers($mill)	NGL Plant($mill)
Base case cost	$500 million per BCF plus $300 million fixed cost	$140,000 per inch mile in AK and $75,00 per inch mile in Canada	$1,650 million per BCF	$175 Million per tanker	$250 million per BCF
All-Alaskan LNG (4.0BCF/DAY)	$2300.00	$5248.00	$6600.00	$1750.00	$875.00
ALCAN Highway Stand-alone (4.5BCF/DAY)	$2550.00	$9964.00	-		$1075
All-Alaskan LNG with spurline (4.5BCF/D)	$2550.00	$6860.00	$7425.00	$1750.00	$975.00
ALCAN Highway with spurline (5BCF/D)	$2800.00	$11336	-		$1200

The operating costs: The operating costs are assumed values set as a percentage of the capital cost (CAPEX) used to evaluate the cost of operating and maintaining the project. The assumed values are shown in Table 4.2

Table 4.2: Operating Cost of the Different Projects

Operation	% of CAPEX
Conditioning Plant	5.4%
Pipeline	2.2%
Separator Plant	4.0%
Liquefaction Plant	4.0%
LNG Ships	2.0%
LPG Ships	2.0%

4.5 Fuel Use and Losses

Fuel use is calculated for each segment including the pipeline, the conditioning plant, the separator plant, the tankers and the LNG plant. The overall fuel use reduces the final quantity delivered and thus reduces the revenue. This will also in turn lower the ROI and the well head value. Table 4.3 shows the assumptions made on fuel loss for each process.

Table 4.3 Fuel Use and Losses for the Model

Operation	Fuel loss
Conditioning plant	4%
TAPS	0%
TAGS	2% per 1000 miles
Separation	3%
LNG liquefaction	4%
Shipping	2%
LPG shipping	1%

4.6 Price

The price for the downstream markets was determined based on forecast and data from the Energy and Information Administration (EIA) of the U.S Department of Energy (DOE)[14]. Using the *Crystal Ball Predictor*, a 30 year gas price forecast was made based on the price history given by the Energy and Information Administration (EIA) of the U.S Department of Energy (DOE)[14].

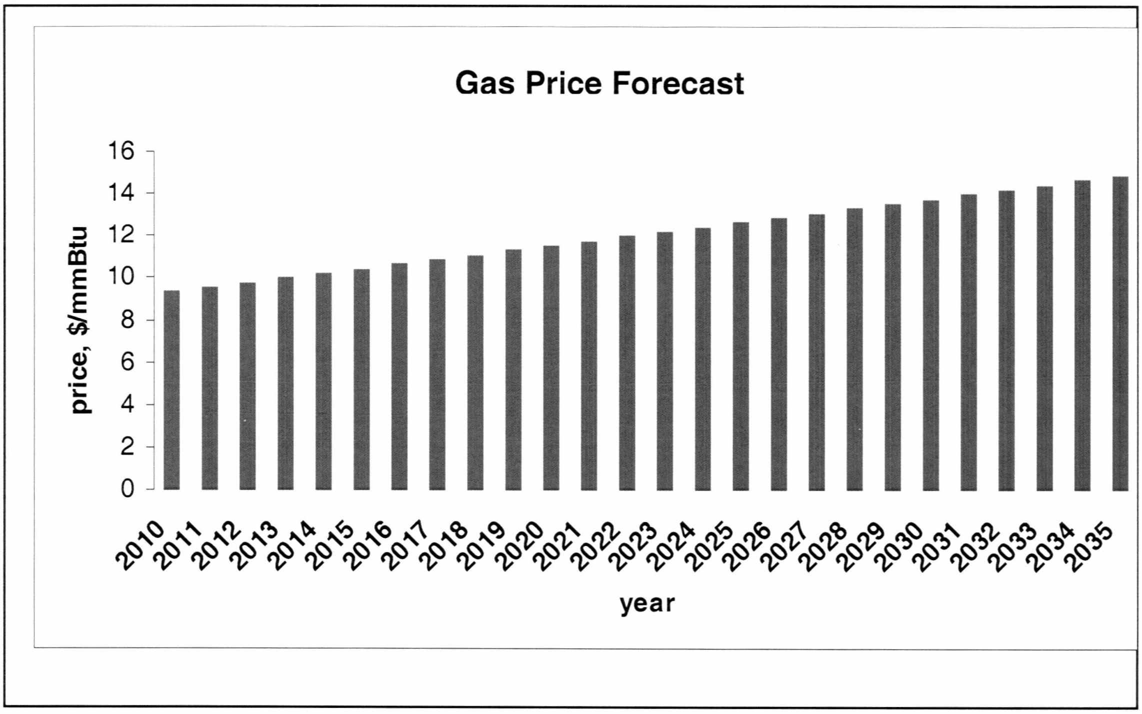


Figure 4.2: Gas Price Forecast

4.7 Tax Rates

Income and property tax rates for different local and national regions are used; each operation is evaluated using the local tax rate. The tariffs for the pipelines are also determined by regional sections so that the local tax rate for that region will be used. Table 4.4 shows a list of the taxes for the different regions used in the CE model.

Table 4.4: Tax Rates

Taxes	
Federal Income Tax Rate	35.0%
Canadian Income Tax Rate	22.0%
Income Tax Depr. Rate	4%
Alaska	
Income Tax Rate	9.4%
Property Tax Rate	2.0%
Royalty Rate	12.5%
Gas Severence Tax Rate	10.0%
Oil Severence Tax Rate	15.0%
Yukon Territory	
Income Tax Rate	15.0%
Property Tax Rate	1.0%
British Columbia	
Income Tax Rate	13.5%
Property Tax Rate	2.5%
Alberta	
Income Tax Rate	13.5%
Property Tax Rate	1.5%

4.8 Construction Pattern

The construction is assumed to start in 2006, and it kes four years to complete the first train in LNG, and also four years for the whole construction in the Alcan project. In this CE model, it is assumed that LNG facilities will be on line within the first year of the completion of the pipeline.

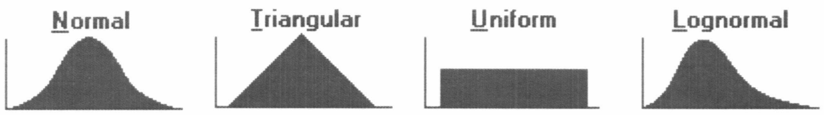
4.9 Depreciation

Depreciation is used to determine the notional amount by which the value of an asset falls every year. The cost of most tangible depreciable property is often recovered for tax purposes using the MACRS (Modified Accelerated Capital Recovery Scheme) methods. In MACRS method, cost and recovery methods are treated the same way whether the property is new or used. It is referred to as accelerated depreciation because it gives deductions faster than with the common straight line depreciation. In the Comparative Economic model, for tax purposes, the capital cost is depreciated using the MACRS.

4.10 Simulation using the Crystal Ball

Crystal Ball is an analytical tool that performs simulations by imitating a real-life system. For each uncertain variable in a simulation, the possible values are defined with a **probability distribution**. A simulation calculates numerous scenarios of a model by repeatedly picking values from the probability distribution for the uncertain variables and using those values for the cell. Crystal Ball simulation calculates hundreds or thousands of scenarios in just a few seconds. In Crystal Ball, distributions and associated scenario input values are called **assumptions**. Assumptions are estimated values of uncertain variables. They are entered and stored in assumption cells.

For every uncertain variable (one that has a range of possible values), the possible values with a probability distribution are defined. The type of distribution selected is based on the conditions surrounding that variable. Distribution types are shown in Figure 4.3:



a b c d

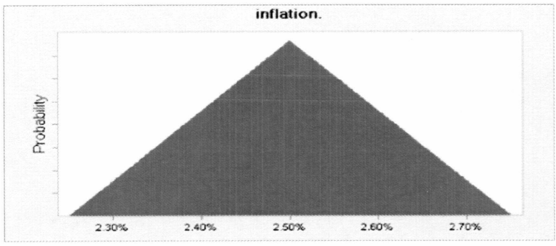
Figure 4.3: Distribution Types

The significance of each distribution is based on the shape. In the uniform and triangular distribution, the base represents the possible range of values, while the height of the triangle represents the probability of the value actually happening. The highest point of the triangle is the most likely value. The lognormal distribution makes use of the standard deviation and the mean of the input data. For simplicity, the triangular distribution was mainly used in this work.

Figure 4.4 shows the triangular distribution of inflation with the most probable value as 2.5%. Figure 4.5 also demonstrates a triangular distribution of equity with the most probable value as 100%. These values represent the assumed values of the parameters used in the CE model.

The probability distributions of the assumptions made are shown:

Assumption 1



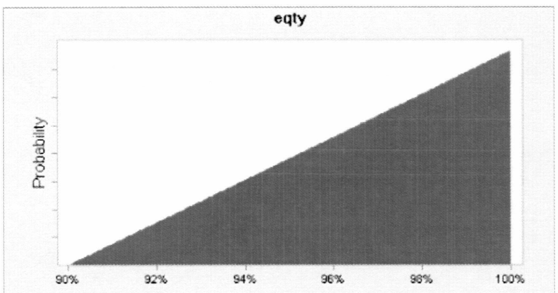
Triangular distribution with parameters:

Minimum	2.25%
Likeliest	2.50%
Maximum	2.75%

Figure 4.4: Inflation

This distribution shows that the inflation value ranges from 2.25% to 2.75%. The peak of the triangle, 2.5% is the most probable value.

Assumption 2



Triangular distribution with parameters:

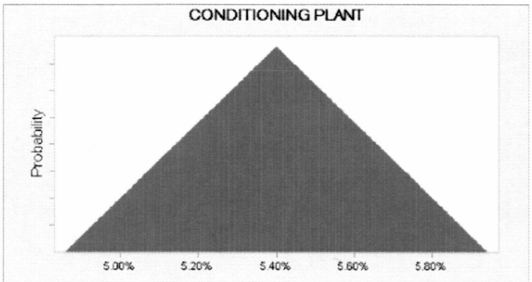
Minimum	90%
Likeliest	100%
Maximum	100%

Figure 4.5: Equity

In the CE Model, the equity was assumed to be 100% for simplicity and thus represented in the probability distribution. The percentage equity ranges from 90% to 100% with the 100% as the most likely value.

The range of values and the most likely values for each assumption used in the CE model are illustrated in Figures 4.6 to 4.20.

Assumption 3



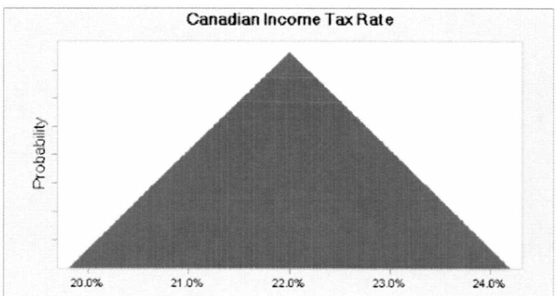
Triangular distribution with parameters:

Minimum	4.86%
Likeliest	5.40%
Maximum	5.94%

Figure 4.6 OPEX Conditioning Plant

Here the conditioning plant Operating Expenditure (OPEX) ranges from 4.86% to 5.94% with the most likely value being 5.4%.

Assumption 4



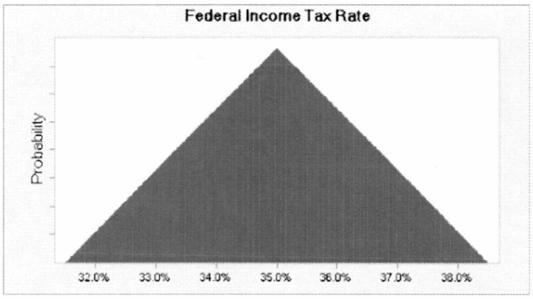
Triangular distribution with parameters:

Minimum	19.8%
Likeliest	22.0%
Maximum	24.2%

Figure 4.7: Canadian Income Tax Rate

The Canadian income tax rate ranges from 19.8% 24.2% with the most likely value being 22%.

Assumptions 5



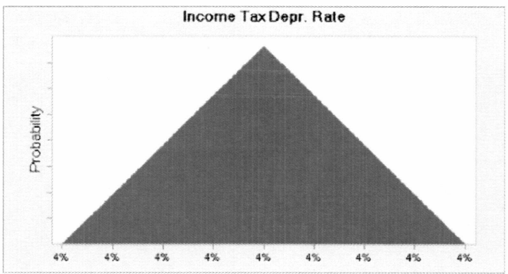
Triangular distribution with parameters:

Minimum	31.5%
Likeliest	35.0%
Maximum	38.5%

Figure 4.8: Federal Income Tax Rate

The Federal income tax rate ranges from 31.5% to 38.5% with the most likely value being 35.0%.

Assumption 6



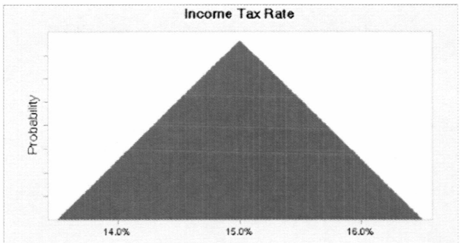
Triangular distribution with parameters

Minimum	4%
Likeliest	4%
Maximum	4%

Figure 4.9: Income Tax Depreciation Rate

The income tax depreciation rate ranges from 4% to 4% with the most likely value being 4%.

Assumption 7



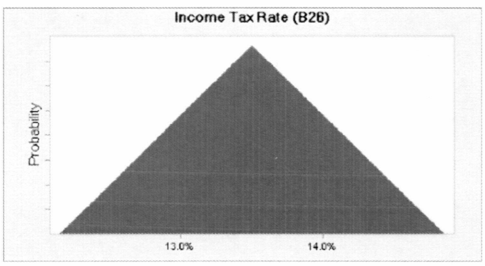
Triangular distribution with parameters:

Minimum	13.5%
Likeliest	15.0%
Maximum	16.5%

Figure 4.10: Yukon Territory Income Tax Rate

The Yukon Territory income tax rate ranges from 13.5% to 16.5% with the most likely value being 15.0%.

Assumption 8



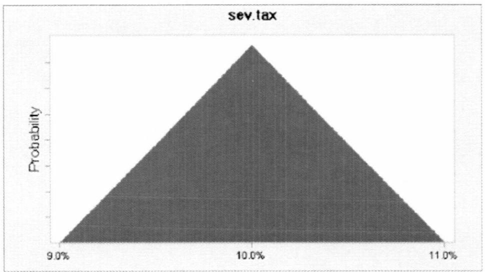
Triangular distribution with parameters:

Minimum	12.2%
Likeliest	13.5%
Maximum	14.9%

Figure 4.11: Alberta and British Columbia Tax Income Rate

The Alberta and British Columbia income tax rate ranges from 12.2% to 14.9% with the most likely value being 13.5%.

Assumption 9

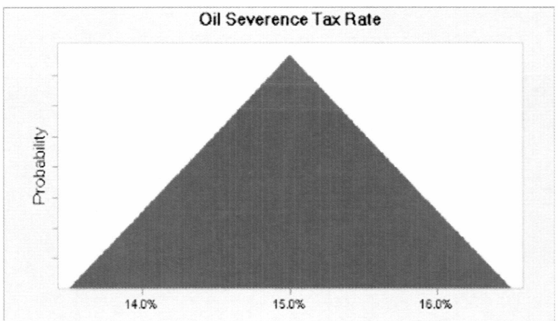


Triangular distribution with parameters:
Minimum 9.0%
Likeliest 10.0%
Maximum 11.0%

Figure 4.12: Gas Severance Tax Rate

The gas severance tax rate ranges from 9.0% to 11.0% with the most likely value being 10.0%.

Assumption 10

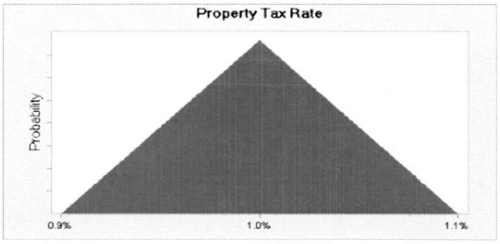


Triangular distribution with parameters:
Minimum 13.5%
Likeliest 15.0%
Maximum 16.5%

Figure 4.13: Oil Severance Tax Rate

The oil severance tax rate ranges from 13.5.0% to 16.5% with the most likely value being 15.0%.

Assumption 11



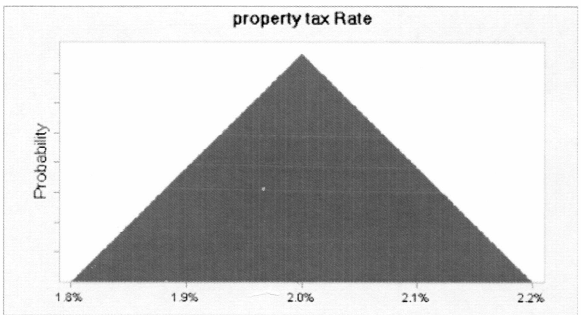
Triangular distribution with parameters:

Minimum	0.9%
Likeliest	1.0%
Maximum	1.1%

Figure 4.14: Yukon Territory Property Tax Rate

The Yukon Territory property tax rate ranges from 0.9% to 1.1% with the most likely value being 1.0%.

Assumption 12



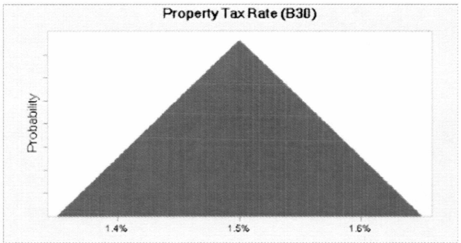
Triangular distribution with parameters:

Minimum	1.8%
Likeliest	2.0%
Maximum	2.2%

Figure 4.15: Alaskan Property Tax Rate

The Alaskan property tax rate ranges from 1.8% to 2.2% with the most likely value being 2.0%.

Assumption 13



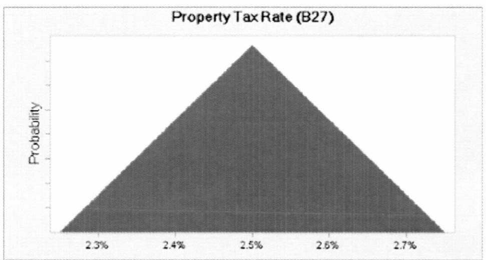
Triangular distribution with parameters:

Minimum	1.4%
Likeliest	1.5%
Maximum	1.7%

Figure 4.16: Alberta Property Tax Rate

The Alberta property tax rate ranges from 1.4% to 1.7% with the most likely value being 1.5%.

Assumption 14



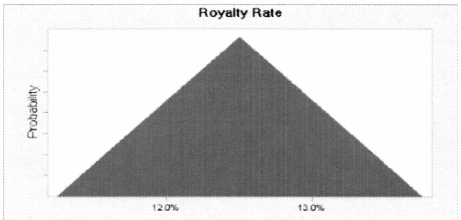
Triangular distribution with parameters:

Minimum	2.3%
Likeliest	2.5%
Maximum	2.8%

Figure 4.17: British Columbia Property Tax Rate

The British Columbia property tax rate ranges from 2.3% to 2.8% with the most likely value being 2.5%.

Assumption 15



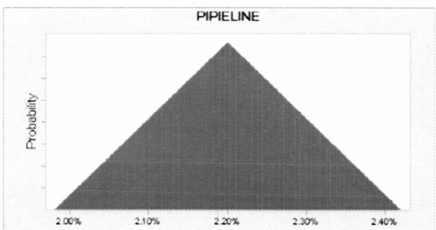
Triangular distribution with parameters:

Minimum	11.3%
Likeliest	12.5%
Maximum	13.8%

Figure 4.18: Royalty Rate

The royalty rate ranges from 11.3% to 12.5% with the most likely value being 13.8%.

Assumption 16



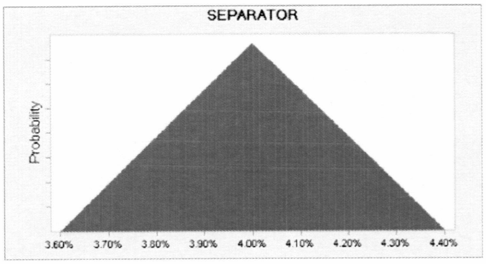
Triangular distribution with parameters:

Minimum	1.98%
Likeliest	2.20%
Maximum	2.42%

Figure 4.19: Pipeline OPEX

The pipeline Operating Expenditure (OPEX) ranges from 1.98% to 2.42% with the most likely value being 2.20%.

Assumption 17



Triangular distribution with parameters:

Minimum	3.60%
Likeliest	4.00%
Maximum	4.40%

Figure 4.20: Separator OPEX

The separator Operating Expenditure (OPEX) ranges from 3.60% to 4.40% with the most likely value being 4.00%.

4.11 Methodology of using the Comparative Economic Model

The term *Model* is not just a spreadsheet that organizes data but also acts as an analytical tool. It represents the relationship between input variables and the output results using a combination of functions, formulas and data. A model portrays the behavior of a real-world system.

The CE model is used to comparatively analyze five possible Alaska natural gas pipeline projects – the Alaskan Canadian (AlCan) Highway stand alone gas pipeline project, the AlCan Highway gas pipeline with an instate spurline to southern Alaska, the All-Alaskan Liquefied Natural Gas Project, the All- Alaskan Liquefied Natural Gas project with a spurline to southern Alaska and the Gas-To-Liquid (GTL) project - by assessing the Return On Investment (ROI) to the project as a whole. This can be done in two ways, by comparing different projects using similar assumptions, and by analyzing each project using its sponsor's assumptions. The GTL project was modeled separately using suitable assumptions. The second purpose of this model is to determine government revenues to determine ways in which varying tax structures may improve profitability with minimal loss to the State. Property taxes are the earliest/largest tax levied by the State. This model gives space for tax incentives and the corresponding effects. These tax incentives portray the maximum effect any politically viable incentive would have on project profitability.

The CE model is very similar to the Northern Economic Research Associates (NERA) model[9] and follows similar reasoning with differences in the prices and cost due to the time interval between the two models. This model is production driven. This means that by changing the input variables like quantity of gas produced, costs will change automatically, allowing one to quickly see the differences (and economies of scale) between projects of varying size.

The analysis this model uses is based on 100 percent equity as a base case. The financing can also be changed easily to also evaluate the projects. For simplicity, this model uses the 100 percent equity to evaluate the projects. This is a little bit in contrary to most producers' project financing. Since different investors have different financing, it will be much simpler to use a common figure to compare the projects.

The well-head value of gas shows if a project is feasible. In this model it is determined by net back pricing. Net back price of gas is the market selling price minus all tariffs. Using the well-head value sometimes poses some problems as a feasibility tool. The problem is that when using the wellhead value to determine the viability of a project, producers will be forced to assure that gas volumes are sold with no change in tariffs in order to pay for the pipeline. When the market becomes volatile, prices change while fixed costs such as the pipeline and other tariffs remain constant. This poses the possibility of the producer bearing the risk of the entire project whether he owns the project or not. It is therefore more appropriate to use the ROI as a feasibility tool rather than the well head value.

Pipeline X refers to that section between Prudhoe Bay and Delta Junction. Pipeline Y refers to the section between the Delta Junction and Alberta. Pipeline C refers to the section between the Delta Junction and the South Shore (Valdez). Capital

Costs contain the capital expenditures used to determine costs on a year by year basis. Although dependent on production, these values may be overwritten by assuming new values. When using the model to analyze a specific project, both production and capital cost can be overwritten.

CHAPTER 5

COMPARATIVE ANALYSIS OF THE DIFFERENT PIPELINE OPTIONS

Cost estimating (economic analysis) is a function of the scope of the project. The better the scope is defined and understood, the better the economic analysis and comparison. Due to the different scopes of the different options, it is actually not easy to make comparisons on the same basis. It is like comparing a particular project with one set of circumstances to another project with different set of circumstances.

5.1 The GTL Project

The GTL plant has a lot of processing units and hence high capital and processing costs. The driving force for the GTL project is the product quality premium (diesel). Its success will be based on the fact that the product quality premium can offset the high Capital Expenditure (CAPEX) and Operating Expenditure (OPEX) of the project. The market for GTL products (middle distillates) is high. The demand for middle distillate is about 35million BPD and growing approximately 4% per year [10]. The proposed GTL plant will produce only 50,000 to 100,000 BPD and this will account for only 0.2% of the total demand and only 5% of the demand growth.

The GTL figures are from the model analysis by Ogugbue[17]. This analysis uses constant crude oil price of $70/bbl and a CAPEX of $30,000 as the base case as outlined in the latter model.

5.1.1 Economic Benefits of GTL

The following are obvious benefits of GTL:

1. GTL technology enables the conversion of stranded gas into low sulfur syngas which is also a feasible alternative for remote LNG transport.
2. Transporting GTL through TAPS might increase the useful life span of the pipeline and thereby improve the economic viability of the pipeline.
3. GTL will reduce the increasing viscosity of Alaskan crude oil, when commingled with the viscous oil, and will make for easy transportation of the oil.
4. The liquid from this technology is stable. This liquid distillate, once converted, is stable and remains in the liquid state. It is a non-aromatic and clean burning fuel with high octane value.
5. The byproduct naphtha is very rich in paraffin. The waxes produced are also useful in food packaging and cosmetics.
6. Dimethlyether, (DME) is a clean fuel and it can be used as a substitute for power plant fuel. Due to its vapor pressure characteristics, which are similar to LPG, it can be used as a household fuel to replace LPG.

5.1.2 Factors Affecting the GTL Option

Although, pipeline cost will not be encountered in this option, there are inevitably conversion plant cost and other factors that will affect this option. Some of the factors will include:

- All transportation costs rely on the existing infrastructure of the oil pipeline operation and maintenance[10].
- Each mode of GTL transportation has an associated capital cost which varies from minimal capital investments for the commingled mode to huge capital costs for the modern batching mode of transportation[10].
- Expansion opportunities are desired: beyond the minimum reserves, ideally 10 - 20 TCF should be available to allow future expansion opportunities (similar to LNG).
- Low gas price is necessary: Just like LNG, GTL projects are very capital intensive and require low-cost feedstock gas that is isolated from high-priced gas markets.
- Rich gas is better: The higher the BTU content of the feedstock gas, the better. Again, like LNG, natural gas liquids can provide additional revenue to support the capital-intensive project.
- Integration opportunities are helpful: If a GTL project can be integrated with other industrial facilities and share common infrastructure, the project will be enhanced.

All the projects have proved to be feasible. But in analyzing all of them to choose the best option, different parameters will be considered. The results from the economic model are used for the consequent analysis. The results are discussed below.

5.2 Payout Period: The number of years it takes the project to recover the total investment on the project. Using the initial investments and the revenue accrued from selling the gas for each project, the payout periods were calculated. The investments include all capital and operating expenses. From the results of the Comparative Economic model used, as shown in Table 5.1, the AlCan stand-alone project gives a payout period of 6 years, the all-Alaskan LNG project 9 years, the all-Alaskan LNG with spurline 10 years, and the AlCan route with spurline 6 years. From the GTL model by Ogubgbue [17], and using a CAPEX of $30,000 and crude oil price of $70/BBL, the payout period is 12 years.

Table 5.1: Payout Period of the Different Projects.

Projects	Total investment	Revenue	Payout Period (years)
All-Alaskan LNG	20,159.	55,341	9
AlCan Highway stand-alone gas pipeline	13,588.6	167,144	6
All-Alaskan LNG project with spurline to southern Alaska	22,042	55,964	9
AlCan Highway gas pipeline with spurline to southern Alaska	15,335.6	166,644	6
GTL Project	30,000	143,236	12

Considering the payout periods, one may want to narrow the options to the AlCan stand-alone and the AlCan route with a spurline to southern Alaska. But the payout period is not the only parameter to effectively analyze a project. Therefore taking a look at the total revenue recovered from each project by the state and federal government and the producers will also give another good parameter for comparison.

5.3 Total Revenue Recovered: This includes both the total tax recovered from the project and the total profits made by the owners. The values were obtained using the tax rates in Table 4.4. Owners profit is the gain any producer or investor will make from selling the gas. This is usually affected by the gas market. Table 5.2 gives a result of the breakdown of all the revenues accrued from each project, while table 5.3 shows the subtotal of all the revenues accrued from Alaskan revenue and the U.S government revenue based on the assumed gas price and tax rates. Tables 5.2 and 5.3 show the revenue accumulated in the different projects. While Table 5.2 is a breakdown of the revenue, Table 5.3 is a total of the revenues accrued from the projects.

Table 5.2: Breakdown of the Revenues Accruable from the Proposed Projects

project	**Income tax** ($Mill)		**Income tariff tax** ($Mill)		**Severance tax** ($Mill)	**Royalty** ($Mill)	Property tax ($Mill)	Owners Profit ($Mill)
	Alaska	USA	Alaska	USA	Alaska	Alaska	Alaska	
All-Alaskan LNG	4,585	15,534	4,233	14,478	5,696	7,120	4,117	81,166
AlCan Highway stand-alone gas pipeline	18,264	61,610	3,931	3,421	24,969	30,428	2,258	214,094
All-Alaskan LNG with Spurline to southern Alaska	3,798	12,901	4,711	16,088	6,431	8,039	4,839	97,756
AlCan Highway gas pipeline with Spurline to southern Alaska	17,819	60,112	4,433	3,520	24,359	29,666	2,668	212,247
GTL		87, 878	8743.3	-	-	-	2161	44,454

Table 5.3: Summary of the Revenues Accruable from the Proposed Projects

PROJECT	ALASKA ($Mill)	US ($Mill)	total
All-Alaskan LNG	25,396	29,945	55,341
AlCan Highway stand-alone gas pipeline	102,113	65,031	167,144
All-Alaskan LNG with Spurline to southern Alaska	27,063	28,901	55,964
AlCan Highway gas pipeline with Spurline to southern Alaska	102,316	64,328	166,644
GTL	-	-	143,236

The components of the revenues are the income tax, income tariff tax, severance tax, property tax and the royalty as shown in table 5.2.

The revenue from the different options can also be compared graphically by analyzing Figures 5.1 through 5.4.

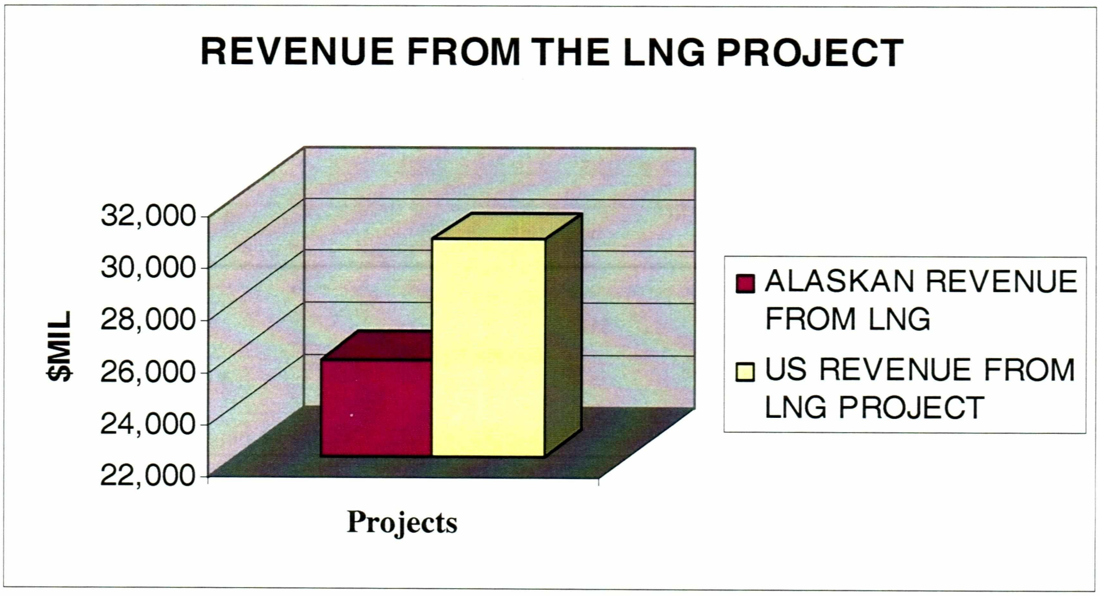


Figure 5.1: Graphical Representation of the Revenue Accruable from the All-Alaskan LNG Stand-alone Project.

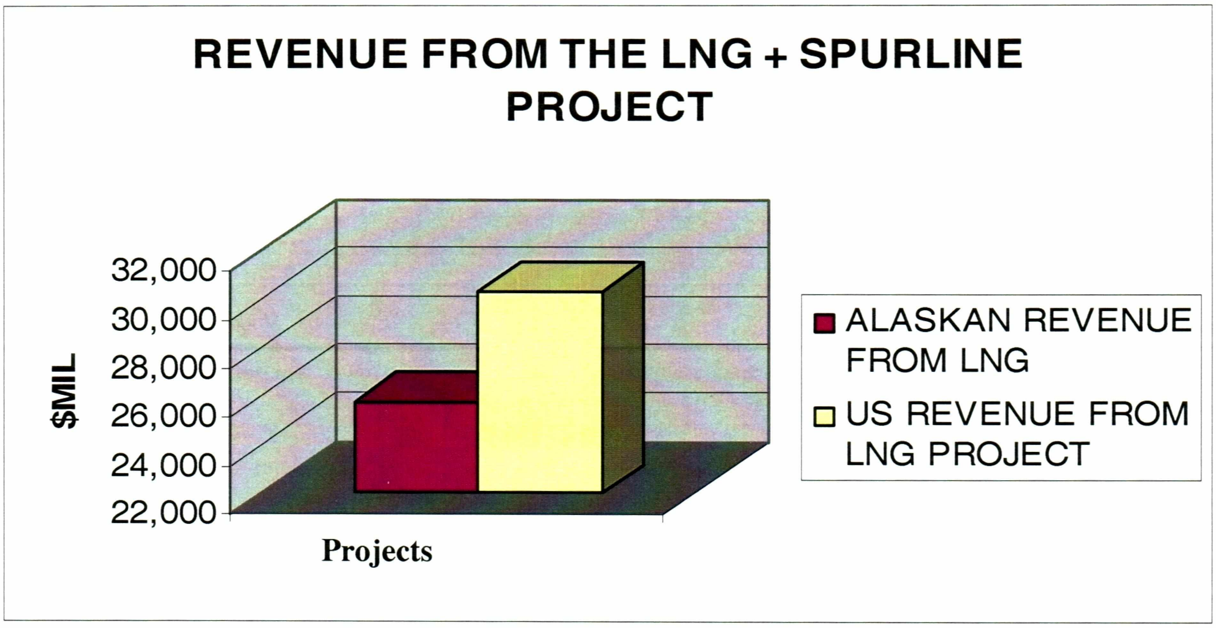


Figure 5.2: Graphical Representation of the Revenue Accruable from the All-Alaskan LNG Project with a Spurline.

From Figures 5.1 and 5.2, a spurline attached to the LNG project did not make much difference in the revenue. This is because the amount of gas (0.5MMscf) assumed to be transported through the spurline is negligible when compared to the amount of gas (4.5MMscf) that will be transported through the mainline.

When considering the Alcan Highway route, Alaska and the US government are not the only beneficiaries from the project. Since the pipeline will pass through Canada, the Canadian government also benefits from the project. From the results of this model, the revenue that the Canadian government will get is so minimal compared to the amount the US government will make. This can be illustrated graphically using Figures 5.3 and 5.4.

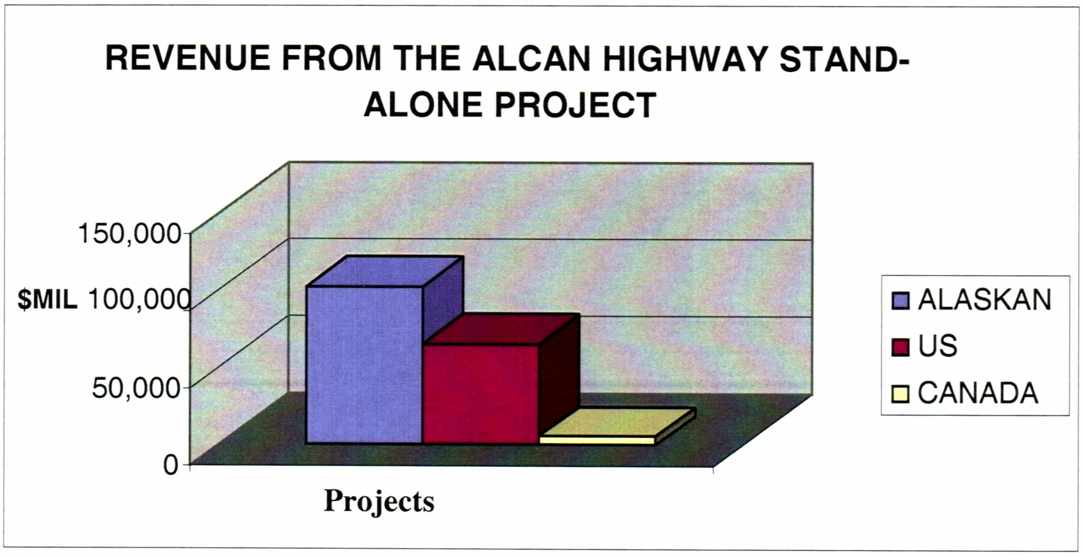


Figure 5.3: Graphical Representation of the Revenue Accruable from the AlCan Stand-alone Project.

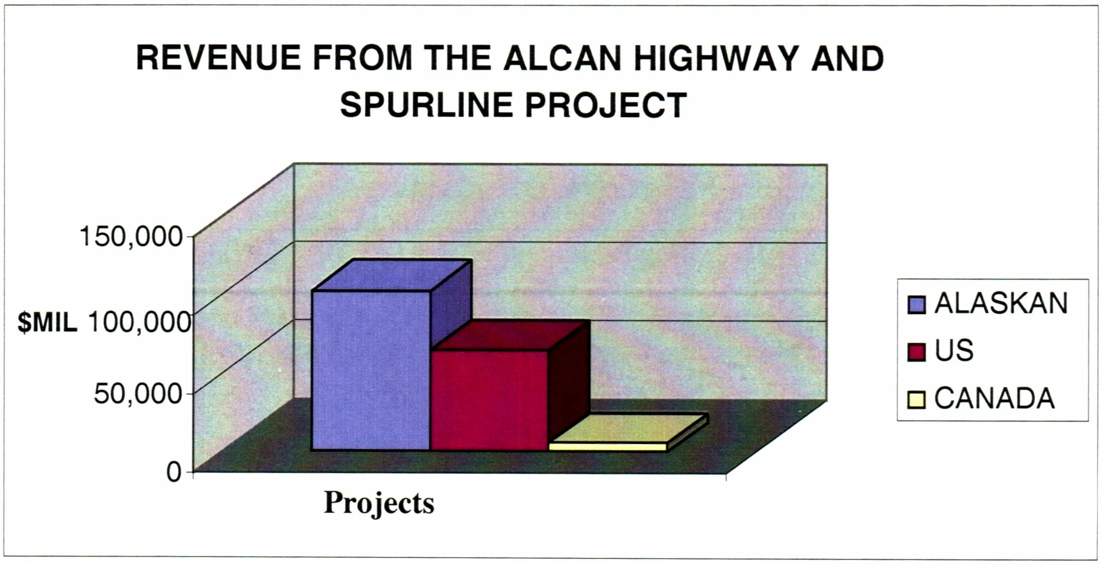


Figure 5.4: Graphical Representation of the Revenue Accruable from the AlCan Highway and Spurline Project.

Again as shown in Figures 5.3 and 5.4, the spurline did not make much difference in the revenue. To put the revenues from all these options together in a graphical manner, Figure 5.5 illustrates the clear difference in all project revenues.

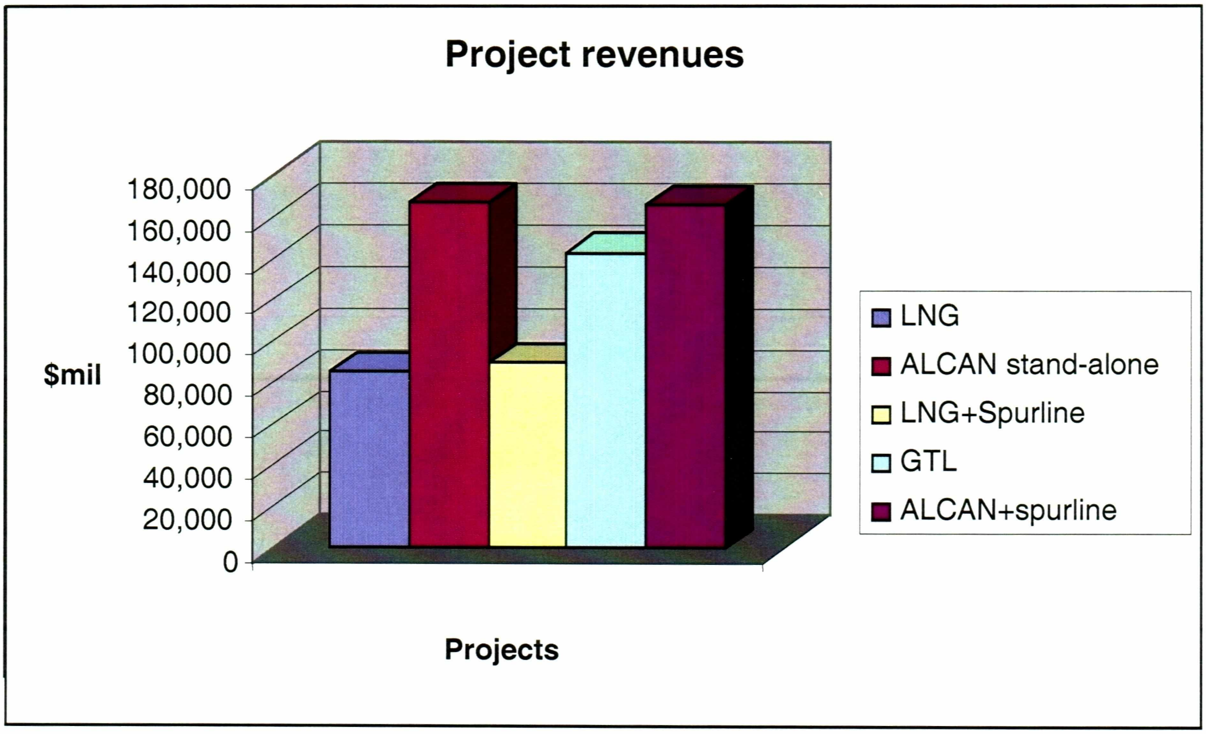


Figure 5.5: Summary of the Projects' Revenues

From the illustrations, the Alcan Highway stand alone project with total revenue of $167,144 million shows the highest total revenue accruable from the project. Using the state and government revenue from the project as a criterion for choosing the best option, then the AlCan stand-alone project should be the best option.

5.4 Profit

The profit generated is another economic tool for analyzing the feasibility of the projects. Deducting the total cost of the project from the revenue accrued from each project gives the profit. Since the first four years will be construction years, there will not be any revenues for those four years. After the construction years, the gas will be sold and then deducting the cost from this revenue will be the profit for each project. The table below shows the profits as calculated in the CE model for each project.

Table 5.4: The Profits Generated from the Different Projects

PROJECT	PROFIT
All-Alaskan LNG	$99,266 mil
AlCan Highway stand-alone gas pipeline	$214,094 mil
All-Alaskan LNG with Spurline to southern Alaska	$110,186 mil
AlCan Highway gas pipeline with Spurline to southern Alaska	$216,010 mil
GTL	-

Table 5.4 is an analytical tool for comparing the economic feasibility of the different projects. The AlCan Stand-alone and AlCan Highway with a spurline have shown to be more economically feasible with more profits than the LNG and GTL projects. The summary of the profits generated from the different projects is illustrated in Figure 5.6.

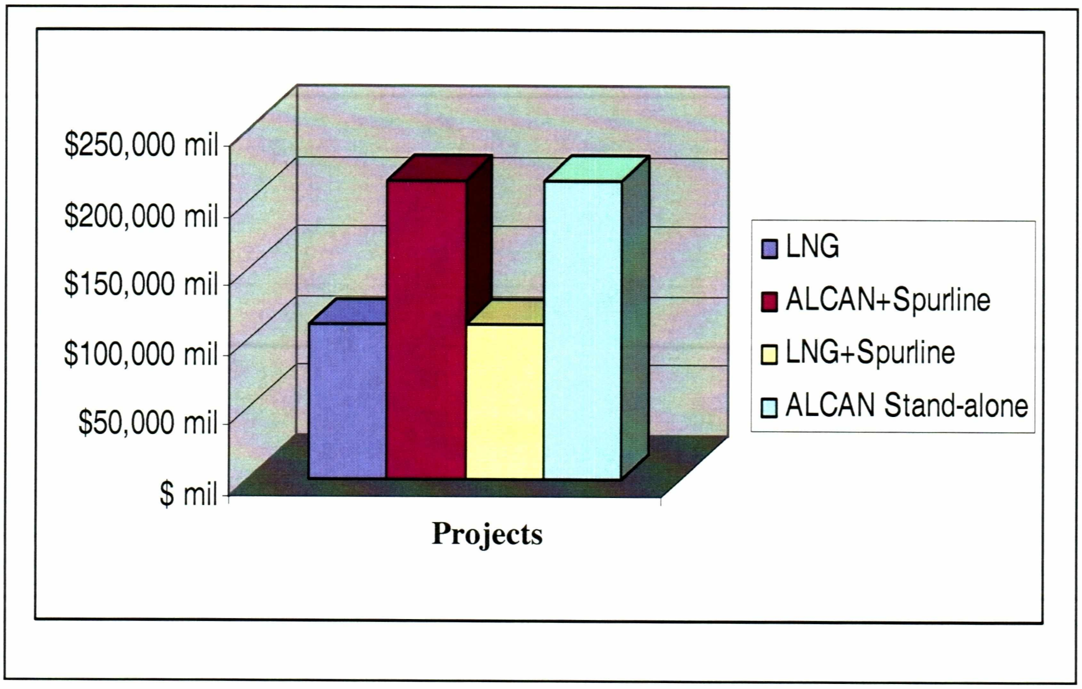


Figure 5.6: Summary of the Profits Generated from the Different Projects

5.5 Return On Investment of the Projects: The Return On Investment is a very important tool for analyzing a project. A higher return on investment means a more feasible project. Based on the profits and expenses generated on each project, the cash flows were discounted into net present value to determine the rate on returns of each project. The returns on investment of different projects are shown in table 5.5.

Comparatively, from the data in Table 5.5, the AlCan stand-alone with return on investment of 33% stands as the more feasible option. The AlCan Highway and a spurline to the interior of Alaska also shows a return on investment close to the AlCan stand-alone. Therefore having a spurline attached to the AlCan Highway project will be profitable and will also help supply natural gas to meet the growing energy demand in southern Alaska.

Table 5.5: The Return On Investment (ROI) of the Different Projects.

All-Alaskan LNG	INVESTMENT ($)	PROFIT ($)	ROI,(%)
AlCan Highway stand-alone gas pipeline	20,159.	99,266 mil	16
All-Alaskan LNG with Spurline to southern Alaska	13,588.6	214,094 mil	33
AlCan Highway gas pipeline with Spurline to southern Alaska	22,042	110,186 mil	16.3
GTL	15,335.6	216,010 mil	32.6
All-Alaskan LNG	30,000		21

5.6 Total Cost of the Projects

The total cost of each project should also be analyzed to estimate how much the owners are ready to invest in to any pipeline project. This is a very important tool in the economic analysis of any project. Since the projects are evaluated at 100% equity, it will be easy to compare the cost of each project. The total cost includes the cost of constructing the pipeline from Prudhoe Bay to Canada or Valdez and the spurline, the conditioning plant and the separator plant. The cost of the GTL project will be the cost of building a GTL plant. The results from the CE model are tabulated in Table 5.6.

Table 5.6: Total Cost of the Different Projects.

PROJECT	TOTAL COST ($Mill)
All-Alaskan LNG	20,159.
AlCan Highway stand-alone gas pipeline	13,588.6
All-Alaskan LNG with Spurline to southern Alaska	22,042
AlCan Highway gas pipeline with Spurline to southern Alaska	15,335.6
GTL	30,000

Considering the cost of the project, the GTL project and the all-Alaskan LNG project are much more expensive and involve a lot of initial cost. The GTL project is much more expensive than the other projects. The AlCan Highway project shows a much lower cost compared to the other projects. It is comparatively less expensive and this makes it economically attractive. If capital is a limiting factor, investors can choose a much cheaper project to embark on.

CHAPTER 6

CONCLUSION AND RECOMMENDATIONS

6.1 Conclusion

The five projects are feasible and can be combined depending on the capital available since there are lots of natural gas reserves in the Alaskan North Slope.

1. There is a high need for Alaskan gas to get to the market due to the high energy demand and utilization in the United States.
2. The North American market provides a more convincing and less volatile market for the Alaskan gas than the Pacific Rim market.
3. They are more economically beneficial than the LNG and GTL projects. They entail fewer processing units and are less expensive.
4. After 30 years of future projection, the AlCan Highway projects (AlCan highway stand-alone and AlCan highway with an instate spurline) gave higher returns on investment when compared with the other projects. With their earlier payout period, they stand as the best options of all the projects. The other projects have longer payout periods.
5. The Alcan Highway with a spurline to southern Alaska has been shown to be economically feasible. The total cost of this project is comparatively low and it shows a high rate on investment when compared to other projects.

6. Though the AlCan Highway stand-alone gas pipeline project has the highest return on investment, the AlCan Highway with a spurline gas pipeline project has shown to be the best of all projects because it has a spurline attached to it which gives Alaska the opportunity to utilize some of its North Slope gas to meet the existing energy demand and also to develop more industries in the state.
7. The all-Alaskan LNG pipeline project also allows in-state economic development. But, this is not as much as the state economic development obtained from an AlCan Highway pipeline project, although it extends to Canada.

6.2 Recommendations

For future studies it is recommended that:

1. Further economic analysis of the AlCan Highway route with a instate spurline project be carried out to evaluate the overall impact at both the state and federal level.
2. The effect of regasification of the LNG should be analyzed and incorporated in the LNG project to account for expenses at the LNG terminal.

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APPENDIX 1

NOMENCLATURE

AK	Alaska
ALCAN	Alaskan Canadian
ANGTA	Alaska Natural Gas Transportation Act
ANS	Alaska North Slope
ANWR	Alaska Natural Wildlife Reserve
APSC	Alyeska Pipeline Service Company
BCF	Billion Cubic Feet
BPD	Barrels Per Day
CAPEX	Capital Expenditure
CDD	Cooling Degree Days
DME	Di Methyl Ether
DOE	Department of Energy
EIA	Energy Information Administration
GTL	Gas-to-Liquids
HDD	High Density Drilling
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MACRS	Modified Accelerated Revenue Recovery Scheme

MCF	Thousand Cubic Feet
MTA	Million Tons per Annum
NERA	Northern Economic Research Associates
NGL	Natural Gas Liquid
NPV	Net Present Value
NPV_{10}	NPV evaluated at a discount rate of 10%.
OPEX	Operating Expenditure
OTT	Over The Top
PBU	Prudhoe Bay Unit
PTU	Point Thompson Unit
ROI	Rate On Investment
TAGS	The Alaskan Gas System
TAPS	Trans-Alaska Pipeline System
WACC	Weighted Average Cost of Capital

APPENDIX 2

GLOSSARY

B

Barrel (bbl): 42 gallons; 5.62 cubic feet; or 0.159 cubic meters.

Barrel of Oil Equivalent (BOE): The oil equivalence of natural gas is normally based on the amount of heat released when the gas is burned as compared with burning a barrel of oil. For a typical natural gas, burning 6,000 standard cubic feet liberates about the same amount of heat as burning one barrel of average crude.

Barrels per day (b/d, bpd, or bbl/d): A unit of measurement used in the industry for the production rates of oil fields, pipelines, and transportation.

Bcf: Acronym for "billion cubic feet". BCF is used to measure the volume of large quantities of natural gas.

British thermal unit (Btu): The standard unit for measuring the amount of heat energy required to raise the temperature of one pound of water by one degree Fahrenheit (1°F) at or near 39.2°F.

C

Capital investment: Money spent for an asset expected to produce income over its useful life.

Carbon: The base of all hydrocarbons; capable of combining with hydrogen in almost numberless hydrocarbon compounds. The carbon content of a hydrocarbon determines, to a degree, the hydrocarbon's burning characteristics and qualities.

Catalyst: In chemical manufacturing, typically a metal-based particle introduced directly in the process stream that increases the rate of a reaction without itself being consumed. Common catalysts in gas processing applications include cobalt, iron, nickel and copper.

Catalytic Process: The refining process of breaking down the larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules. It is also a process by which reaction occurs in the presence of certain agents which were formerly believed to exert an influence by mere contact.

Cetane number: A measure of how readily the fuel burns. A fuel with a high cetane number starts to burn shortly after it is injected into the cylinder; it has a short ignition delay period. Conversely, a fuel with a low cetane number resists auto-ignition and has a longer ignition delay period.

Cubic feet per day (cf/d): At standard conditions, the number of cubic feet of natural gas produced from a well over a 24 hour period, normally an average figure from a longer period of time. Generally expressed as mcf/d = thousand cubic feet per day, mmcf/d = million cubic feet per day, or bcf/d = billion cubic feet per day.

Cubic foot: The amount of gas required to fill a volume of one cubic foot under stated conditions of temperature, pressure, and water vapor.

- SCF = Standard Cubic Foot (One cubic foot of gas at standard conditions, i.e. 14.73 psia and 60° F without adjustments for water vapor)
- MCF = One Thousand Cubic Feet (Multiply by 1,000)
- MMCF = One Million Cubic Feet (Multiply by 1,000,000)
- BCF = One Billion Cubic Feet (Multiply by 1,000,000,000)

D

Demand forecast: A projection of the level of energy or capacity that is likely to be needed at some time in the future.

Department of Energy (DOE): The government agency responsible for regulating energy sources, including natural gas.

Depreciation: Reduction in the book or market value of an asset.

Discount rate: The interest rate that the Federal Reserve charges a bank to borrow funds when a bank is temporarily short of funds.

Distribution system: This refers to a delivery system that delivers utility natural gas, electricity, water) to a household or commercial business.

E

Equity Capital Financing: Money given to your business, without the intention of paying it back, in return for part ownership of your business. Banks do not ordinarily provide this type of financing.

F

Feedstock: Raw material required for an industrial process.

Fischer-Tropsch gas-to-liquids conversion: A method for converting natural gas to liquid products, often called synthetic crude, developed by German chemists Hans Fischer and Franz Tropsch. Synthesis gas, which is made from natural gas, is passed over a catalyst that leads to the formation of hydrocarbon liquids.

G

Gas field: A field or group of reservoirs of hydrocarbons containing natural gas but insignificant quantities of oil.

Gas processing: The separation of oil and gas, and the removal of impurities and natural gas liquids from natural gas.

Gas reserves: Those quantities of gas which are anticipated to be commercially recovered from known accumulations from a given date forward.

Gas revenue: The product of gas volume and gas price; gross cash flow from sales of gas.

Gas-to-liquids (GTL): Refers to processes that convert natural gas to ambient liquid fuels, such as diesel, naphtha, kerosene, DME and methanol.

Gas well: A well drilled and completed that primarily produces natural gas.

H

Hurdle rate: This is the minimum allowable rate on investment for a project to be economically feasible.

M

Middle Distillates: Any of the wide range of products produced by distillation, as distinct from bottoms, cracked stock, and natural gas liquids. Distillate products have a 'mid-boiling range,' and include gas oil and kerosene.

P

Permafrost: This refers to a soil that has been frozen for two or more years.

Probability: An evaluation that explicitly accounts for the likelihood and consequences of possible accident sequences in an integrated fashion.

R

Return-On Investment: refers to the benefits to an investor relative to the cost of the initial investment.

S

Syngas (from ***syn**thesis **gas***)**:** This is the name given to the gas of varying composition that is generated in coal gasification and some types of waste-to-energy facilities. The name comes from their use in creating synthetic petroleum for use as a fuel or lubricant via Fischer-Tropsch synthesis.

Syncrude: Synthetic crude typically refers to crude that has been created from full or partial upgrading of oilsands or very heavy crude.

T

TCF: One Trillion Cubic Feet (Multiply by 1,000,000,000,000).